UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Qualifying Facilities Rates and Requirements	)	Docket No. RM19-15-000
Implementation Issues Under the Public Utility Regulatory Policies Act of 1978	))	Docket No. AD16-16-000

COMMENTS OF THE EDISON ELECTRIC INSTITUTE

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I. INTRODUCTION

The Edison Electric Institute ("EEI") respectfully submits the following comments in response to the Notice of Proposed Rulemaking ("NOPR") issued by the Federal Energy Regulatory Commission ("FERC" or "Commission").[1] EEI is the association that represents all investor-owned electric companies in the United States. Our members provide electricity for about 220 million Americans and operate in all 50 states and the District of Columbia. As a whole, the electric power industry supports more than 7 million jobs in communities across the United States. EEI's members are committed to providing affordable and reliable electricity to customers now and in the future.

Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") requires all electric utilities[2] to purchase electricity at the "incremental cost of alternative electric energy" from qualifying small power producers or qualifying co-generation facilities, referred to as Qualifying Facilities ("QFs").[3] As electric utilities, all EEI members are subject to PURPA's requirement that they purchase from and sell energy to QFs at just and reasonable rates, commonly known as the mandatory purchase obligation, unless granted an exemption by the Commission.[4] To date, no EEI member has received a complete exemption or waiver from the PURPA purchase mandate under section 292.309 of the Commission's PURPA regulations.[5] As such, all EEI members are directly affected by the issues raised in the NOPR.

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[1] *Qualifying Facilities Rates and Requirements,* 168 FERC ¶ 61,184 (2019) ("NOPR").

[2] Electric utility is defined in part as a person or Federal or State agency that sells electric energy. *See* 16 U.S.C § 796 (22).

[3] *See* 16 U.S.C. § 824a-3(d).

[4] *See* 18 C.F.R. § 292.309.

[5] The Commissions regulations implementing PURPA are contained in 18 C.F.R § 292.

The Commission established regulations implementing PURPA in 1980. The nation's energy landscape today is far different than it was in 1980 when the Commission enacted those regulations. Open access to transmission, greater competition among generators in organized and bilateral wholesale markets, improvements in technology, lower costs of technology, and implementation of state and federal policies have all helped drive changes in the fuel mix so that generation from co-generation and renewable energy resources, such as wind and solar, has increased substantially. PURPA requires that the Commission provide regulations for implementation and update those regulations from time-to-time.[6]

In light of these changes, the Commission's rules regarding PURPA are no longer just and reasonable and do not reflect today's energy markets. It has been over forty years since the Commission enacted most of its regulations implementing PURPA. Thus, the Commission has appropriately acted to review and update its regulations implementing PURPA as required by the statute. The proposals in the NOPR are consistent with the requirements of PURPA and provide certainty and opportunities to QFs, while at the same time better ensuring that states have the flexibility to meet PURPA's consumer protection mandates. Accordingly, as discussed herein, EEI supports the proposals in the NOPR.

II. BACKGROUND AND EXECUTIVE SUMMARY

PURPA was enacted to promote long-term economic growth by reducing the nation's reliance on oil and gas, encourage the development of alternative energy sources, and thereby combat a nationwide energy crisis.[7] As the United States Supreme Court explained in *FERC v. Mississippi*, "Congress believed that increased use of these [nontraditional] sources of energy

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[6] 16 U.S.C. § 824a-3(a).

[7] *N. Y. State Elec. & Gas Corp. v. Saranac Power Partners L.P.*, 117 F. Supp. 2d 211, 216 (N.D.N.Y. 2000), *aff'd*, 267 F.3d 128 (2d Cir. 2001).

would reduce the demand for traditional fossil fuels."[8] The core of PURPA is the requirement in Section 210 that all electric utilities purchase electricity at the "incremental cost of alternative electric energy" from QFs.[9] In order to effectuate PURPA's purchase mandate, "Congress directed FERC to prescribe, within one year of the statute's enactment, rules requiring electric utilities to deal with qualifying cogeneration and small power production facilities," which the Commission did in Order Nos. 69[10] and 70.[11] In Order No. 69, the Commission defined the "incremental cost of alternative electric energy" as the electric utility's avoided costs which are "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[12] When Congress enacted PURPA, it required that the Commission update the its PURPA regulations from time to time.[13]

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[8] 456 U.S. 742, 750-51 (1982).

[9] 16 U.S.C. § 824a-3(d).

[10] *Small Power Production and Cogeneration Facilities; Regulations implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128, 45 Fed. Reg 12214 (Feb. 25, 1980), *order on reh'g*, Order No. 69-A, FERC Stats. & Regs. ¶ 30,160 (1980), *aff'd in part and vacated in part, Am. Elec. Power Serv. Corp. v. FERC*, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part, Am. Paper Inst., Inc. v. Am. Elec. Power Serv. Corp*., 461 U.S. 402 (1983)). Citations to Order No. 69 are to the version published in the Federal Register.

[11] *Small Power Production and Cogeneration Facilities - Qualifying Status*, Order No. 70, 10 FERC ¶ 61,230 (1980), *subsequent history omitted*.

[12] 18 C.F.R. § 292.101(b)(6). *See Am. Paper Inst., Inc. v. Am. Elec. Power Serv. Corp*., 461 U.S. 402, 405 (1983) ("*API*"). The Supreme Court further explained how the Commission's methodology for determining avoided cost rates would evolve over time:

> Because the full-avoided-cost rule is subject to revision by the Commission as it obtains experience with the effects of the rule, it may often be in the interest of a qualifying facility to negotiate a long-term contract at a lower rate. The Commission's rule simply establishes the rate that applies in the absence of a waiver or a specific contractual agreement. . . . Under these circumstances it was not unreasonable for the Commission to prescribe the maximum rate authorized by PURPA. The Commission's order makes clear that the Commission considered the relevant factors and deemed it most important at this time to provide the maximum incentive for the development of cogeneration and small power production, in light of the Commission's judgment that the entire country will ultimately benefit from the increased development of these technologies . . . .

API at 418.

[13] 16 U.S.C. § 824a-3(a).

In 2005, in light of the growth of wholesale markets, Congress amended PURPA through the Energy Policy Act of 2005 ("EPAct 2005") and added section 210(m), which gave the Commission the authority to terminate the mandatory purchase obligation if specific criteria are met. Despite this recognition by Congress of the evolution in the energy markets, the Commission took a conservative approach in interpreting Section 210(m) by instituting the 20 megawatt ("MW") threshold and not providing a mechanism for electric utilities outside of markets operated by regional transmission organizations ("RTO") or independent system operators ("ISO") to demonstrate that they met the statutory requirements for exemption.[14] In 2006, when enacting the regulations to implement Section 210(m), the Commission did not conduct a holistic review of its regulations implementing PURPA to determine if additional changes were needed in light of the changes in the industry between 1980 and 2006.

In recognition of the changes in the industry, since the vast majority of the PURPA regulations were enacted in 1980, the Commission issued a Notice of Technical Conference on February 9, 2016, announcing that it would hold a technical conference on June 29, 2016, to discuss implementation issues under PURPA.[15] On March 4, 2016, the Commission issued a supplemental notice of technical conference that invited panelists to discuss issues associated with the mandatory purchase obligation, application of the one-mile rule, the 20 MW threshold in competitive markets, and the calculation of avoided cost.[16] Panelists discussed these and other

[14] *Revised Regulations Governing Small Power Production and Cogeneration Facilities*, Order No. 671, 114 FERC ¶ 61,102. (2006), *subsequent history omitted*; *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Order No. 688, 117 FERC ¶ 61,078 (2006), *subsequent history omitted*; *Revisions to Form, Procedures, and Criteria for Certification of Qualifying Facility Status for a Small Power Production or Cogeneration Facility*, Order No. 732, 130 FERC ¶ 61,214 (2010).

[15] *Implementation Issues Under the Public Utility Regulatory Policies Act*, Docket No. AD16-16-000, Notice of Technical Conference (Feb. 9, 2016).

[16] *Implementation Issues Under the Public Utility Regulatory Policies Act*, Supplemental Notice Concerning Technical Conference, Docket No. AD16-16-000 (Mar. 4, 2016).

issues during the technical conference held on June 29, 2016.[17] On September 6, 2016, the Commission issued a Notice Inviting Post-Technical Conference Comments.[18] Post-technical conference comments were filed on November 7, 2016, and since that date, the docket has been active with parties filing supplemental comments.

The Commission's proposals in the NOPR reflect the extensive record that has been developed to date and they appropriately implement the requirements of PURPA, as modified by Congress in 2005. Based on the record, the proposals in the NOPR provide clarity to the states by including guidance on the tools available to establish avoided cost rates as well as update regulations that were created by the Commission in originally implementing the statute, such as the one-mile rule, 20 MW threshold, and self-certification rules, which are not required by PURPA. Finally, the NOPR appropriately recognizes the significant transformation in the energy markets since the Commission enacted the majority of its PURPA regulations in 1980. Wholesale markets have grown and matured. As discussed herein, electric utilities are no longer the only producers of energy. Independent power producers, large and small, increasingly generate and supply renewable energy. As state and federal policies increasingly require the use of renewable energy and technology costs decline, the move toward the increased use of these resources will only continue to grow. The proposals in the NOPR appropriately recognize these changes and fulfill the Congressional mandate for the Commission to update its regulations implementing PURPA.

Recognizing and codifying the tools available to states to use market-based and competitive methods to determine avoided costs rates will spur, rather than reverse, competitive

[17] *See* Transcript for the June 29, 2016 Technical Conference on Implementation Issues under the Public Utility Regulatory Policies Act of 1978, Docket No. AD16-16-000 (July 8, 2016) ("Transcript").

[18] *Implementation Issues Under the Public Utility Regulatory Policies Act*, Notice Inviting Post-Technical Conference Comments, Docket No. AD16-16-000 (Sept. 6, 2016).

market development and clarify that states have the tools necessary to help ensure that customers have the benefit of just and reasonable rates. As discussed herein, while creating the first class of competitive generators, PURPA also sought to ensure that electric utility customers would not over pay for this generation. As detailed in the report by Concentric Energy Advisors ("Concentric"),[19] attached hereto as Attachment A, this is not always the case today. The proposals in the NOPR will provide certainty to QFs, while, at the same time, providing states with the tools and guidance to ensure that the consumer protection mandates of PURPA are met. Accordingly, the NOPR's proposals are consistent with the letter and spirit of PURPA.

III. THE COMMISSION HAS APPROPRIATELY ACTED TO UPDATE ITS PURPA REGULATIONS

The vast majority of the Commission's PURPA regulations were enacted in 1980 with the issuance of Order Nos. 69 and 70. A few of the key regulations were amended in 2006 to reflect EPAct 2005, with minor adjustments made to the regulations in 2010.[20] With the passage of time, the resource mix for electric generation has changed and the resources and methods available to states to determine avoided costs have changed. When Congress enacted PURPA, it explicitly recognized this possibility by expressly delegating authority to the Commission to update its regulations from time-to-time.[21] This delegation to the Commission to interpret and implement the statute has also been recognized by the courts.[22] The United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") has held that

[19] *An Empirical Analysis of Avoided Cost Rates for Solar and Wind QFs Under PURPA*, Concentric Energy Advisors (Nov. 2019) (Concentric) (Included as Attachment A hereto).

[20] *See* Order Nos. 688, 732.

[21] 16 U.S.C. § 824a-3(a).

[22] PURPA is not self-implementing, it is a "regulatory statute," *see API* at 417, which takes meaning and authority from its attendant regulations. *See Chevron U.S.A., Inc. v. Natural Resources Defense Council*, 467 U.S. 837, 843–44, (1984) ("The power of an administrative agency to administer a congressionally created ... program necessarily

> The Commission's only obligations under § 210 are the promulgation and periodic revision of these regulations and of the exemption regulations required by § 210(e). . . . The D.C. Circuit added that "the breadth of agency discretion is, if anything, at [its] zenith when the action assailed relates primarily not to the issue of ascertaining whether conduct violates the statute, or regulations, but rather to the fashioning of policies, remedies and sanctions. . . . In other words, the Commission ordinarily has remedial discretion, even in the face of an undoubted statutory violation, unless the statute itself mandates a particular remedy."[23]

Accordingly, it is appropriate for the Commission to update its regulations implementing PURPA to reflect the changes in the market, to recognize the growth in competitive generation, to address uncertainty caused by judicial decisions and ensure that states have the tools necessary to implement PURPA in a manner that is just and reasonable for electric utility customers.

A. The Electric Industry Has Fundamentally Transformed Since the Commission Adopted the PURPA Regulations in 1980.

PURPA was part of a package of legislative proposals that sought to reduce dependence on oil and natural gas in light of an energy crisis largely spurred by a lack of domestic supply and an embargo from certain foreign nations. One answer was to encourage electric utilities to purchase from nontraditional generators. When enacting PURPA, Congress felt that two problems impeded the development of non-traditional generating facilities which in turn would reduce the dependence on foreign fuel sources: (1) electric utilities were reluctant to purchase power from, and to sell power to, the non-traditional facilities, and (2) the regulation of these alternative energy sources by state and federal utility authorities imposed financial burdens upon the non-traditional facilities, thus discouraging their development.[24]

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requires the formulation of policy and the making of rules to fill any gap left, implicitly or explicitly, by Congress."). In such case "there is an express delegation of authority to the agency to elucidate a specific provision of the statute by regulation. Such legislative regulations are given controlling weight unless they are arbitrary, capricious, or manifestly contrary to the statute." *Id*. Lower courts have explained that "Congress merely announced the goal of promoting the development of alternative energy sources in PURPA and left the details of how to do so to FERC. . . . " *N. Y. State Elec. & Gas Corp. v. Saranac Power Partners L.P.*, 117 F. Supp. 2d 211, 231 (N.D.N.Y. 2000), *aff'd*, 267 F.3d 128 (2d Cir. 2001).

[23] *Conn Valley Elec. Co. v. F.E.R.C.*, 208 F.3d 1037, 1043-1044 (D.C. Cir. 2000) (internal citations omitted).
[24] *FERC v. Mississippi*, 456 US 742, 750-51 (1982).

As a result of these concerns, Congress created a class of third-party generators that were not subject to the same requirements, regulations, and oversight as electric utilities. Congress also required electric utilities to purchase electricity from these generators at just and reasonable rates that left customers indifferent to the source of the energy. The Commission subsequently promulgated regulations implementing PURPA.

At the time the PURPA regulations were initially promulgated almost forty years ago:

- Most investor-owned utilities ("IOUs") were fully-integrated providers of generation, transmission, and distribution;

- Nearly all IOUs had sole rights to serve retail customers in their state commission-determined service areas;

- Most wholesale public- or cooperatively-owned utilities were captive to an IOU, due to a lack of open access transmission;

- The Commission had not adopted a *pro forma* open access tariff with *pro forma* generator interconnection provisions and there were no power marketers, merchant generation or independent power producers;

- All electric utilities lacked market-based rates ("MBR") authority and regulations providing regulation of entities selling power only under MBR authority did not exist;

- There was no retail competition or restructuring that required IOUs to divest its generation;

- RTOs/ISOs with competitive markets were about two decades away from forming;

- The concept of exempt wholesale generators ("EWGs") did not exist;[25] and

- Federal and state policies providing incentives to and encouraging renewable generation did not exist.

The above conditions have significantly changed.

[25] The Energy Policy Act of 1992 amended the Federal Power Act ("FPA") to create a new class of exempt wholesale generators ("EWG") to sell power into the wholesale market.

First, as to utilities' willingness to buy power from nontraditional entities, some states have restructured and required their IOUs to divest their generation, a few states do not permit IOUs to own or build new generation, two-thirds of end use customers in the United States are served by electric utilities that participate in markets operated by RTOs/ISOs, and all IOUs now buy energy from nontraditional generators (i.e., generators that are not owned by other integrated utilities) to supplement energy they obtain from their own resources (if any). While fully-integrated utilities with defined service areas still exist, there have been profound changes in the manner in which these utilities procure power for their retail load. Virtually every state commission, through integrated resource planning, closely monitors procurement decisions or even mandates that procurement be based on competitive solicitations. The proposals in the NOPR update the regulations to reflect the changes in the industry and provide additional clarity, which can be of benefit to QFs and customers.

Second, in enacting PURPA, Congress was concerned that non-traditional generators would be subject to the same regulations as electric utilities, and that such "burden" of traditional electric utility regulation would hinder the development of these new domestic alternative energy resources. By creating a new category of generation providers through PURPA, Congress sought to ensure that a new class of generators would not be subject to utility-style regulation.

> The Conferees wish to make clear that cogeneration is to be encouraged under this section and therefore the examination of the level of rates which should apply to the purchase by the utility of the cogenerator's or small power producers power should not be burdened by the same examination as are utility rate applications but rather in a less burdensome manner.[26]

Since PURPA created the first class of competitive generators almost forty years ago, Congress has enacted statutes requiring open access to transmission and further encouraging the growth of

[26] Conference Report on PURPA, H.R. Rep. No. 1750, 95th Cong., 2nd Sess. 97-98.

EWGs that have MBR authority. EWG status largely exempts generators from state regulation, other than siting regulations. EWG status also eliminates or reduces Public Utility Holding Company Act regulations. Furthermore, since passage of the Energy Policy Act in 1992 and 2005, the Commission has implemented regulations enabling the growth of markets and open access for all resources.[27] Thus, today, generators that sell at market-based rates already are subject to greatly reduced regulatory burdens as compared to electric utilities, unrelated to any requirement under PURPA. With the growth of markets, market rules have evolved to reflect that there are players in the market that do not have the same obligation (e.g. to serve or ensure reliability) as electric utilities, and as such are not subject to the same level of regulation. As a result of the changes in the markets, third-party independent power producers have grown exponentially.

Today, independent power producers, including QFs, are providing the majority of renewable energy capacity in the United States. Between January 1, 2010 and October 1, 2019, independent power producers, including smaller resources, provided 89% of the solar and wind capacity in the United States.[28] Between January 1, 2010 and October 1, 2019, in non-RTO/ISO territories, independent power producers added 11,184 MW of solar and wind capacity, while QFs added 9,392 MW and electric utilities added 4,151 MW. In RTO/ISO markets, independent power producers added 62,123 MW, QFs added 10,754 MW and electric utilities added 7,424

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[27] *See e.g., Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmission Utilities,* Order No. 888, 75 FERC ¶ 61,080 (1996); Regional Transmission Organizations, Order No. 2000, 89 FERC ¶ 61,285 (1999); *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266 (2007); *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071 (2008); *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 61,127 (2018).

[28] Compilation of data provided by EEI Business Analytics based on source data from © 2019 ABB, The Velocity Suite.

MW.[29] Thus, the markets have evolved so that independent power producers are not only able to develop, finance, and sell renewable energy, but are able to provide more renewable energy than electric utilities. This is true in RTO/ISO markets as well as non-RTO/ISO areas. While customers in some areas of the country have seen reduced prices due to the growth in renewable generation, as demonstrated by Concentric, customers are not seeing the benefits of growth, through reduced prices, equally due to pricing of PURPA contracts.[30] It is therefore time for the Commission to revise its PURPA regulations to reflect today's energy industry.

B. The Generation Fuel Mix, Renewable Technology Prices, State Laws, and Consumer Sentiment Have Evolved Since PURPA Regulations Were Promulgated.

One focus of PURPA was to reduce reliance on oil and natural gas as fuels for electric generation. Such focus was based on the volatility in the price of oil prices caused by the Organization of the Petroleum Exporting Countries embargo and a widely held belief that natural gas reserves were dwindling quickly. It was expected that fuel prices would continue to swing in both directions by large magnitudes. Due to the fluctuations in oil and gas prices in particular, "[t]he Commission believed that any overestimations or underestimations [of avoided costs] 'will balance out.'"[31] The belief was that (due to the many variables impacting fossil fuel prices), actual avoided costs would continue to vary widely over time.[32] In addition, at the time, few renewable technologies were cost-effective, even with high gas and oil prices. As noted in the

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[29] *Id.*

[30] *See* Attachment A.

[31] NOPR at P 68 (citing Order No. 69).

[32] *E.g., N. Y. State Elec. & Gas Corp. v. FERC*, 117 F.3d 1473, 1475 (D.C. Cir. 1997) (finding that FERC "could neither engage in 'minute-by-minute' recalculation of rates nor subject utilities and cogenerators to the uncertainty that frequent recalculation would produce."). The court quoted FERC's position that the regulation was (and, in the opinion of the FERC, remained) a fair compromise designed to reconcile the requirement that the rates for purchases equal the utilities' avoided cost with the need for QFs to be able to enter into contractual commitments based, by necessity, on estimates of future avoided costs. *Id.* at 1475.

NOPR, the rationale that over and under-estimations would balance out over time may no longer be valid.[33]

The generation cost landscape has changed dramatically in the past forty years. The use of oil-fired generation has significantly decreased since PURPA was enacted as the use of natural gas and renewables for electric generation has increased. The discovery of accessible additional natural gas reserves in the United States radically altered the economics of gas-fired generation. Price decreases in renewable technology have been profound and tax policies have made renewable resources even more economic. Recent energy storage technology improvements have further altered the economics of renewables in a favorable manner that, in itself necessitates a review of the Commission's rules implementing PURPA as applied to energy storage technologies.

According to the Energy Information Administration ("EIA"), natural gas generating capacity in the United States is forecast to increase 30 percent between 2018 and 2025, increase 42 percent between 2018 and 2030, increase 53 percent between 2018 and 2035, increase 63 percent between 2018 and 2040, and increase 86 percent between 2018 and 2050.[34] With respect to renewables, EIA reports that renewables and hydroelectric generating capacity in the United States is forecast to increase 42 percent between 2018 and 2025, increase 51 percent between 2018 and 2030, increase 63 percent between 2018 and 2035, increase 82 percent between 2018 and 2040 and increase 122 percent between 2018 and 2050.[35] Thus, as noted by the

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[33] NOPR at P 30.

[34] U.S. Energy Information Administration Annual Energy Outlook 2019--Electric Power Projections by Electricity Market Module Region (Reference Case), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2019&cases=ref2019&sourcekey=0

[35] U.S. Energy Information Administration Annual Energy Outlook 2019, Renewable Energy Generating Capacity and Generation by Electricity Market Module Region (Reference Case). https://www.eia.gov/outlooks/aeo/data/browser/#/?id=16-AEO2019&cases=ref2019&sourcekey=0

Commission, two things are clear: (1) there is cheap and plentiful natural gas, and (2) the levelized cost of electricity from renewables is approaching that of traditional generation.[36]

This was not the situation when PURPA was enacted. Despite the burgeoning environmental movement of the 1960s and 1970s, many of the studies related to climate science had not begun;[37] states were not mandating that utilities purchase from renewable resources; and large and small corporations and individual consumers were not demanding green energy to meet their energy needs. Times have changed. Today, twenty-nine states plus the District of Columbia have renewable portfolio standards and eight states have renewable portfolio goals. These state requirements have resulted in about half of the renewable energy generation built since 2000.[38] In addition, state net metering tariffs provide smaller QFs "rates" in excess of avoided cost.[39] The resulting increased demand for renewable energy has significantly changed the non-PURPA related opportunities available to small power production QFs.

Due to these changes, the generation fuel mix for electric generation has transitioned from one that was 48 percent coal in 2008 to one that is now comprised of approximately 1/3 coal, 1/3 natural gas and 1/3 carbon-free resources.[40] This trend in the replacement of coal

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[36] NOPR at PP 19-21. *See* Lazard, *Lazard's Levelized Cost of Energy Analysis Version 13.0* (Nov. 2019), *available at* http://www.thinkgeoenergy.com/latest-lazard-levelized-cost-of-energy-analysis-published-nov-2019/ ("Lazard Analysis").

[37] The first NASA Goddard Institute for Space Studies global temperature analysis was published in 1981. It was ten years *after* PURPA enactment that NASA scientist, James Hansen first reported to the Senate that he was ninety-nine percent certain the earth was warmer then than it had ever been measured to be, there was a clear cause and effect relationship with the greenhouse effect.

[38] *See e.g.*National Conference of State Legislature, State Renewable Portfolio Standards and Goals, http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx. (last updated Nov. 1, 2019).

[39] Some states have come to recognize that paying credits for energy at a full retail price is not a sustainable economic model.Nonetheless, net metering tariffs have significantly encouraged the development of small QFs. In some states, net metering encourages QF development to a far greater degree than the PURPA purchase mandate.

[40] *See* U.S. Energy Information Administration, Electric Power Annual 2018 Report, Table 3.1.A (Net Generation by Energy Source), https://www.eia.gov/electricity/annual/html/epa_03_01_a.html; id., Table. 3.1.B (Net Generation by Renewable Source), https://www.eia.gov/electricity/annual/html/epa_03_01_b.html.

generation with lower-carbon resources will continue. Due to these changes, at the end of 2018, the electric industry's carbon dioxide emissions were 27 percent below 2005 levels, and are now below the transportation sector.[41] Based on publicly announced goals, this trend will continue as EEI members collectively seeks to reduce carbon emissions by 50 percent by 2030 and 80 percent by 2050 compared with peak 2005 levels.

C. Court Decisions Interpreting Commission Regulations Implementing PURPA Have Raised Uncertainty.

In addition to the Commission's PURPA regulations, judicial and Commission precedent also address PURPA implementation. Appellate courts recently have interpreted PURPA regulations in an inconsistent manner, which has created regulatory uncertainty for states. For example, both a Massachusetts federal district court[42] and United States Court of Appeals for the Ninth Circuit ("Ninth Circuit") decision[43] have interpreted 18 C.F.R. § 292.304(d)(2)(ii) in a manner that does not permit sellers seeking to use avoided cost rates from adopting a formula rate methodology at the time a legally enforceable obligation ("LEO") is formed. Both courts interpreted the PURPA regulation to mean that *all* aspects of an avoided cost rate must be fixed at the time of the LEO. The PURPA contract found by the Ninth Circuit to be non-compliant with PURPA (the California Standard Contract for QFs 20 MW or under) was reviewed by the Commission in two orders,[44] with the Commission finding that it "is consistent with PURPA."[45]

[41] This information was developed using the U.S. Energy Information Administration's Monthly Energy Review for October 2018. *See* U.S. Energy Information Administration, Monthly Energy Review (Oct. 2018), https://www.eia.gov/totalenergy/data/monthly/archive/00351810.pdf

[42] *Allco Renewable Energy Ltd. v. Mass.Elec. Co.*, 208 F. Supp. 3d 390, 400 (D. Mass. 2016), *aff'd*, 875 F.3d 64 (1st Cir. 2017).

[43] *Winding Creek Solar LLC v. Peterman*, 932 F.3d 861 (9th Cir. 2019).

[44] *Winding Creek Solar LLC*, 151 FERC ¶ 61,103 (2015), *reh'g denied*, 153 FERC ¶ 61,027 (2015).

[45] *Id.* at P 7.

Thus, the Commission's adoption of 18 C.F.R. § 292.304(d)(2) would provide clarity to courts applying the Commission's regulations.

Furthermore, in 2010, the Commission overturned long-standing precedent and permitted state commissions to adopt different avoided cost rate methodologies for differing types of resources if a state mandate required purchases from such resources and the utility had a need for such resources to meet the mandate.[46] In 2019, the Ninth Circuit took the prior 2010 decision a step further. In *CARE v. CPUC*,[47] the court held:

> Although FERC initially stated in *CPUC* that a "state may take into account obligations imposed by the state that, for example, utilities purchase energy from particular sources of energy," *CPUC*, 133 FERC at ¶ 61266 (emphasis added), later in *CPUC*, FERC reiterated that when a state has a requirement that utilities source energy from a particular type of generator, "generators with those characteristics constitute the sources that are relevant to the determination of the utility's avoided cost for that procurement requirement." *Id.* at ¶ 61267. Thus, where a state has an RPS and the utility is using a QF's energy to meet the RPS, the utility cannot calculate avoided costs based on energy sources that would not also meet the RPS.

The dissent disagreed, explaining that "[t]he majority cherry picks a sentence from *CPUC* to reach its result."[48] Judge Nguyen observed:

> Nothing in *CPUC* implies that states are required to consider supply characteristics. To the contrary, both in *CPUC* and the regulations it interprets, the repeated use of terms such as "may," "permits," and "consistent with" all suggest that it is a matter of state discretion.[49]

While these cases are not binding on other states, they do serve as guidance, which creates uncertainty and litigation risk for states, QFs, and electric utilities. To address the

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[46] *Cal. Pub. Util. Comm'n*, 133 FERC ¶ 61,059, at P 20 (2010) (*CPUC*).

[47] *Californians for Renewable Energy v. Cal. Pub. Utils. Comm'n*, 922 F. 3d 929 (9th Cir. 2019) (*CARE v. CPUC*).

[48] *Id*. at 944.

[49] *Id*.

uncertainty caused by the conflicting judicial decisions, the Commission should update its regulations to ensure that states have clarity on the options available to them in implementing the Commission's regulations. Similarly, if a court interprets the Commission's PURPA regulations in a manner with which the Commission disagrees, as markets and times change, then the Commission should provide clarity to the states and market participants by updating its regulations.

D. The Commission Has Acted Appropriately to Modernize Its Regulations to Ensure that the Requirements of PURPA Are Met.

PURPA provides simple directives for purchases of QF power by electric utilities: "the rates for such purchases – 1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and 2) shall not discriminate against qualifying cogenerators or qualifying small power producers."[50] PURPA also directs that the rate for purchases of QF power shall not "exceed[] the incremental cost to the electric utility."[51] These directives make clear that PURPA was not intended to require utility customers to pay significantly more for QF power than for power from other resources. Rather, utility customers should be indifferent as to whether a utility purchases from a QF, purchases from a non-QF merchant generator, or generates power from its own resources.

Congress never intended that electric utility customers subsidize QFs. As noted in the Conference Report on PURPA, "the provisions of this section are not intended to require the rate payers of a utility to subsidize cogenerators or small power producers."[52] The Conference Report also recognized that QFs bear some risks:

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[50] 16 U.S.C. 824-1-3(b).

[51] 16 U.S.C. 824a-3(b).

[52] Conference Report on PURPA, H.R. Rep. No. 1750, 95th Cong., 2nd Sess. 97-98 (1978).

> The conferees recognize that cogenerators and small power producers are different from electric utilities, not being guaranteed a rate of return on their activities generally or on the activities vis a vis the sale of power to the utility and whose risk in proceeding forward in the cogeneration or small power production enterprise is not guaranteed to be recoverable.[53]

Thus, the term "encourage," as used in the statute, was meant to ensure that electric utilities bought QF energy if it was available at rates that reflect the utility's other options. The Commission has recognized that "[t]he intention [of Congress] was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly encouraged alternatives."[54] The Commission's obligation under PURPA is to provide regulations and options to states so that states have the tools necessary to ensure that avoided cost rates are not unjust and unreasonable for an electric utility's customers. This component of the statute is just as important as the requirement to encourage QFs. These consumer protection provisions mean that if a QF cannot turn a profit given a utility's true avoided cost(s), the states are not permitted to use *PURPA* to provide *additional* encouragement. That said, the states certainly may, through resource procurement mandates, carbon fees, and many other tools, encourage renewables or cogeneration in a manner other than requiring utility customers to pay rates above true avoided costs.

To date, the Commission's regulations and guidance implementing PURPA have been interpreted in ways that have resulted in some states adopting policies that have resulted in rates that are not just and reasonable to utility customers and that have provided preferential pricing or contractual terms for QFs over other renewable resources not procured through PURPA. This outcome is inconsistent with the clear words of the statute, which requires customers to be

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[53] *Id.*

[54] *S. Cal. Edison Co.*, 71 FERC ¶ 61,269, at 62,080 (1995) (*SCE*). EEI recognizes that *SCE* was reversed in 2010 and that multiple avoided costs may exist if a state has a purchase mandate that a QF is fulfilling.

indifferent to the source of the electricity. For example, in testimony filed with the South Carolina Public Service Commission, Duke Energy Carolinas and Duke Energy Progress reported that their customers are currently over-paying \$2.26 billion for 4,000 MW of solar power.[55] In January 2018, Consumers Energy Vice President Timothy J. Sparks provided testimony before the United States House of Representatives' Energy & Commerce Committee's subcommittee on Energy regarding proposed PURPA reforms. Mr. Sparks's testimony demonstrated that Consumers Energy customers paid almost \$300 million above market to QFs for renewable energy from 2005 to 2015.[56] These examples underscore the need for additional clarity embodied by the NOPR's proposals.

The Concentric study also demonstrates that the implementation of PURPA has not left customers indifferent, but rather has resulted in the procurement of over-priced power, as compared to other available alternatives. Concentric analyzed a sample of 708 solar and wind QF contracts representing approximately 8,000 MW of generation capacity. Concentric found that these contract rates with QFs consistently exceeded rates in competitively determined purchase power agreements executed in the same year for solar and wind energy and estimated, in the end, customers overpaid between \$150.7 million and \$216.2 million per year relative to competitive benchmarks. Accounting for the full term of the solar and wind QF contracts raises the total overpayment estimate to between \$2.7 billion and \$3.9 billion.[57]

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[55] *South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Carolinas, LLC's and Duke Energy Progress LLC's Standard Offer Avoided Cost Methodologies, From Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended)* – S.C. Code Ann. Section 58-41-20(A), Direct Testimony of George V. Brown on Behalf of Duke Energy Carolinas, L.L.C. and Duke Energy Progress, L.L.C at p. 16, lines 3-7, NCUC Docket Nos. 2019-185-E, 2019-186-E (Aug. 14, 2019).

[56] Before the Committee on Energy and Commerce Subcommittee on Energy United States House of Representatives, Written Testimony of Timothy J. Sparks, Vice-President of Electric Grid Integration, Consumers Energy, a CMS Corporation (Jan 19, 2018).

[57] Concentric at 20.

As recognized in the NOPR, the energy landscape has changed significantly since the Commission adopted the current PURPA regulations. As such, it is appropriate for the Commission to review and update its rules as required by the statute. Due to the evolution of the energy markets, the Commission's current regulations implementing PURPA can result in the uneconomic development of QFs at the expense of the electric utility's customers and other more competitive resources. The Commission has acted appropriately and within its authority to update its regulations implementing PURPA.

IV. COMMENTS ON COMMISSION PROPOSALS

Commissioner Glick notes that the Commission's "responsibilities under PURPA are three-fold: (1) to encourage the development of [QFs] ; (2) to prevent discrimination against QFs by incumbent utilities; and (3) to ensure that the resulting rates paid by electricity customers remain just and reasonable and in the public interest."[58] As discussed below, the Commission's PURPA regulations will continue to accomplish all of these goals if revised as proposed.

A. The Commission Appropriately Gives Discretion to the States to Determine Avoided Cost.

As explained above, there has been significant growth in renewable energy provided by independent power producers, including QFs, in just the past ten years. Although renewable prices have declined, customers in affected states have not seen the benefit of lower prices for energy procured under PURPA contracts. Based on its examination of 704 solar and wind QF contracts representing approximately 8,000 MW of capacity in seven states, Concentric found that:

[58] NOPR, Dissent of Commissioner Glick, at P 1 ("Commissioner Glick Dissent").

> On an annual levelized cost basis, the solar QF contracts signed between 2013 and 2019 exceeded a competitive market rate by between $6.27/MWh and $10.79/MWh in 2018 dollars. We also estimate this cost-per-MWh differential results in an estimated overpayment relative to the market-based alternative of between $67.9 million and $116.8 million per year for the solar QF contracts we reviewed. Accounting for the full term of the solar QF contracts raises the total overpayment estimate to between $1.05 billion and $1.87 billion.
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> For wind QF contracts signed between 2009 and 2018, we estimate that QF contract rates are between $17.66/MWh and $21.19/MWh higher on an annual levelized basis than comparable market-based contract rates. The differential for the wind QF contracts we reviewed results in estimated overpayments relative to a market-based alternative of between $82.9 million and $99.4 million per year we reviewed. Accounting for the full term of the wind QF contracts raises the total overpayment estimate to between $1.65 billion and $1.99 billion.[59]

Accordingly, the Commission has acted appropriately within its authority to update its regulations to clarify that states can use, in addition to the existing methods, alternative market-based methods for setting avoided costs. Many of the alternative options provided in the NOPR are or have been used by individual states. It is therefore appropriate for the Commission to update it regulations to provide clarity to the states that market-based methods for setting QF avoided cost rates are acceptable.

Specifically, with regards to the energy component of the avoided cost rate, the Commission proposes that:

> States have the flexibility to require that "as-available" QF energy rates paid by electric utilities located in RTO/ISO markets be based on the market's locational marginal price (LMP) or similar energy price derived by the market, in effect at the time the energy is delivered.
>
> States have the flexibility to require that "as-available" QF energy rates paid by electric utilities located outside of RTO/ISO markets be based on competitive prices determined by: (1) liquid market hub energy prices; or (2) formula rates based on observed natural gas prices and a specified heat rate.
>
> States have the flexibility to require that energy rates under QF contracts and other LEOs be based on as-available energy rates determined at the time of delivery rather than being fixed for the term of the contract or other LEO.

[59] Concentric at 2.

> States in RTO/ISO markets have the flexibility to instead implement an alternative approach of requiring that the fixed energy rate be calculated based on estimates of the present value of the stream of revenue flows of future LMPs or other acceptable as-available energy rates at the time of delivery.[60]

Providing this additional clarifying guidance in addition to other existing methodologies such as anticipated or actual marginal cost identified by the utility (regardless of whether an RTO exists), reinforces that each approach is a just and reasonable means of establishing the as-available avoided cost rate for compensating QFs and therefore reduces uncertainty for all affected parties. In addition to these options for setting as-available rate, the Commission also proposes to make clear that states can use competitive procurement to set energy and/or capacity rates.[61] This also is appropriate.

The express inclusion of these additional options in the Commission's regulations not only provides clarity to the states, but also appropriately recognizes that there are different market structures and other regional differences that necessitate the use of different tools. The NOPR explains that the Commission "intends that the states will continue to have 'great latitude' in determining how to apply the revised rules, provided that such application is reasonably designed to implement any new rate provisions that may be adopted, as well as the other already-existing provisions of the PURPA Regulations."[62] Giving this flexibility to the states is in the best interest of customers and will allow states to work with the electric utilities to establish avoided costs in a manner that meets the need of QFs and the electric utility's customers. As recognized by Concentric:

> Setting QF contract rates administratively without regard to current market conditions, can also result in inefficient investment over time because such rates encourage developers to locate in jurisdictions with the highest avoided cost rates as opposed to

[60] NOPR at P 32.

[61] *Id*. at P 33.

[62] *Id*. at P 35.

> areas where solar and wind energy would be most effectively deployed, and therefore valuable to the utility and its customers.[63]

As discussed below, EEI generally supports the Commission's proposals to clarify the broad authority that states have in establishing avoided cost rates. The Commission's proposals will ensure that QFs are not treated in a discriminatory manner, and provide states with additional tools to establish just and reasonable rates. This includes the Commission's proposal to not revise how the existing PURPA regulations inform how state commissions may treat a QF's interest in selling capacity when it is not needed so that "an electric utility is not required to pay for QF capacity that the state has determined is not needed."[64] This policy appropriately protects customers and provides QFs clarity that they should strive to locate in areas where capacity reserves are declining.

1. LMP is the appropriate energy rate to be used in RTO/ISO markets.

EEI supports the Commission's proposal to "permit a state the flexibility to set the as-available energy rate paid to a QF by an electric utility located in a RTO/ISO at LMPs calculated at the time of delivery."[65] Locational Marginal Price, or LMP, is the cost to buy and sell power at different locations within an RTO/ISO and is a way for wholesale electric energy prices to reflect the value of electric energy at different locations, accounting for the patterns of load, generation, and the physical limits of the transmission system. All of the resources that sell energy into organized wholesale markets, either day-ahead or in real-time, receive the LMP. It is inherently non-discriminatory pricing that results from a Commission regulated market overseen by independent market monitors that have consistently found the markets to be competitive.

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[63] Concentric at 18.

[64] NOPR at P 33 and n.58.

[65] *Id*. at P 43.

The Commission has "recognized that LMPs 'reflect the true marginal cost of production, taking into account all physical system constraints, and these prices would fully compensate all resources for the variable cost of providing service.'"[66] Based on the locational aspect of resources and location-specific needs for those resources, and Congress' recognition of the growth of competitive markets through the enactment of section 210(m), the Commission "preliminarily finds that LMP is an accurate measure of avoided costs."[67] EEI agrees.

The concept of using LMP for QFs selling on an as-available basis is nothing new. In RTO/ISO markets, the incremental costs to an electric utility of electric energy is the LMP and, as such, it is an accurate measure of avoided costs. As noted by the Commission, some states with utilities in FERC-jurisdictional RTO/ISO markets -- Maryland, New Jersey, North Carolina, Virginia, Connecticut, New Hampshire, Kentucky, Michigan, and Texas -- have already set avoided cost rates at LMP.[68] EEI appreciates the Commission providing clarity to these states and other states within RTOs/ISOs that confirms they can "adopt LMP as a per se appropriate measure of the as-available energy component of avoided costs."[69]

Those states that have adopted LMP pricing for as-available QFs have explained their rationales, which are in line with the Commission's rationale. For example, the Public Utility Commission of Texas stated that:

> If a QF provides power to [Southwestern Public Service Company (SPS)] in a given hour, the price that SPS avoids by taking the QF power is the price SPS would have paid in the Integrated Marketplace for replacement energy. Therefore, the locational marginal price (LMP) established in the [SPP] Integrated

[66] *Id*. at P 77.

[67] *Id*. at P 45-46.

[68] *Id*. at P 50.

[69] *Id*.

> Marketplace at the settlement location applicable to a QF is SPS's actual avoided cost.
>
> The LMP is SPS's avoided cost because, if a QF does not provide non-firm power in a given hour, SPS will serve its load by purchasing replacement energy from a generator with the same LMP or nearly the same LMP.[70]

In states where excess energy results even after accounting for net metering, such sales are as-available. For example, the Wisconsin Public Service Commission has found the LMP appropriate:

> WEPCO is obligated to purchase power from CGS8 generators. In instances where the process of netting is used, such as in the case of the CGS8, it is only when the amount of energy generated exceeds the customer's consumption over the netting period that a sale to the utility occurs, and only in the net excess amount. Consistent with PURPA, this sale is made at an avoided cost rate. The Commission finds WEPCO's CGS8 tariff, modified so as to require that customers be paid for annual net surplus generation at an avoided cost rate, to be reasonable.[71]

The Commission's action here is well-founded and simply reflects existing practices adopted by several states.

2. The Commission provides appropriate options for states outside of RTOs/ISOs to determine energy rates.

As to non-RTO/ISO regions, they too may occasionally be host to a QF that only seeks to provide power on an occasional basis pursuant to its own schedule. Accordingly, the Commission proposes additional options for states that are not located in RTO/ISO markets to determine energy rates.[72] In particular, the NOPR states that:

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[70] *Application of Sw. Pub. Serv. Co. for Auth. to Revise Its Tariff for Purchase of Non-Firm Energy from Qualifying Facilities,* No. 42180, 2015 WL 307153, at *2 (Jan. 21, 2015).

[71] *Joint Application of Wisconsin Elec. Power Co. et al.*, No. 5-UR-106, 2012 WL 6707032 (Dec. 21, 2012) (a transmission avoidance payment is also provided).

[72] The Commission notes that states are still free to "under the Commission's existing PURPA Regulations, to

> The Commission proposes to revise the PURPA Regulations in 18 CFR § 292.304 to add a subsection (b)(7) which, in combination with new subsection (e)(1), would permit a state to set the as-available energy rate paid to a QF by electric utilities located outside of RTO/ISO markets at a competitive price (Competitive Price) calculated at the time of delivery. Competitive Prices would be defined as: (1) energy rates established at liquid market hubs; or (2) energy rates determined pursuant to formulas based on natural gas price indices and a proxy heat rate for an efficient natural gas combined-cycle generating facility.[73]

EEI generally supports these proposals because they appropriately clarify that the use of market-based, competitive pricing is permissible in states located outside of RTOs/ISOs, providing greater certainty to QFs. That said, EEI notes that the Commission's prior regulations never prohibited such approaches, but were merely silent on whether they were acceptable.

First, the Commission affirms that states may determine that prices at a liquid Market Hub to which the purchasing utility has reasonable access can equate to competitive prices. A state can use these prices to set an avoided cost rate if the state identifies the Market Hub used to set price and makes a determination that the "competitive prices at the hub actually relate to the costs an electric utility would avoid but for the purchase from the QF."[74] The Commission provides a non-exhaustive list of factors that states could use in making the determination.[75] In response to the Commission's question as to additional factors that need to be considered, the proposed list of factors is appropriate and additional factors need not be specified as the

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determine that competitive energy prices included in an electric utility's power purchase agreement represent the electric utility's avoided cost of energy and to set avoided cost energy rates for that utility based on its contract rate." NOPR at P 60.

[73] *Id*. at P 51

[74] *Id*.at P 56.

[75] *Id*. at P 57.

proposed factors require the states to show that the hub is liquid and that price formation is transparent.[76]

EEI supports the Commission's proposal and agrees that Market Hub prices are similar to LMP in that they provide transparency and a proxy for avoided costs if the required determination is made by the state. Commission precedent recognizes that Market Hubs constitute liquid markets and that the prices at such Market Hubs are representative of competitive market pricing.[77] This is particularly true in the western United States where the Commission has regularly approved electric utilities' use of published prices at Market Hubs with ample liquidity, such as the Mid-Columbia or Palo Verde hubs, to set prices.[78] Furthermore, the Commission has permitted electric utilities to use an average of Market Hub prices to establish Commission-jurisdictional rates.[79] Thus, some states may be located in regions with access to more than one Market Hub and those states should have the flexibility to use an average of Market Hub prices or develop a formula correlated to the appropriate Market Hubs to develop the electric utility's avoided cost.[80]

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[76] *Id*. ("The Commission seeks comment on additional factors or standards for consideration by the states in determining whether liquid trading hubs could be used to set an electric utility's as-available energy avoided cost rate.").

[77] *E.g., Price Discovery in Natural Gas and Electric Markets*, 109 FERC ¶ 61,184, at P 66 (2004) (finding that Commission-jurisdictional tariffs may rely upon published prices at Market Hubs to establish prices).

[78] *See El Paso Electric Co.*, 148 FERC ¶ 61,051, at P 7 (2014) ("We find that El Paso has provided adequate support for its proposal to use Palo Verde index prices to prices imbalance charges."); *Idaho Power Corp.*, 121 FERC ¶ 61,181, at P 27 (2007) (accepting proposal to use Mid-Columbia prices to set energy imbalance charges); *Pinnacle West Energy Corp.*, 92 FERC ¶ 61,248, at 61,671, (2000) ("The Commission has repeatedly held that capping the pass-through of prices resulting from affiliate transactions by reference to competitive prices at recognized market hubs provides an effective mechanism to prevent affiliate abuse."). FERC's State of the Market Report for 2018 also discusses the increased information available in natural gas price indices resulting in an increasing volume of transactions settling off next day and next month. Federal Energy Regulatory Commission, Office of Enforcement, Division of Energy Market Oversight, State of the Market Report 2018 (Apr. 2019), https://www.ferc.gov/market-assessments/reports-analyses/st-mkt-ovr/2018-A-3-report.pdfThe.

[79] *PacifiCorp*, 95 FERC ¶ 61,463, at 61,463 (2001).

[80] NOPR at P 58 ("The Commission seeks comment on whether under this proposal a state should be permitted to set QF rates at energy prices in a region that are based on a formula that includes adjustments to the market hub

Second, the Commission proposes that for regions where there are no RTO/ISO markets or Market Hubs, that states may establish avoided cost at the marginal price of energy generated by an efficient natural gas combined cycle facility located in the region.[81] The Commission requires states to find that the resulting combined cycle combustion turbine price represents an approximation of the purchasing utility's avoided costs and provides a list of factors for states to consider using in this analysis. EEI supports states having the ability to elect this option and supports the factors outlined by the Commission if the state chooses to use a combined cycle price.[82] However, the Commission should acknowledge a state's flexibility to allow for the use of another type of generation resource, as appropriate, to determine the purchasing utility's avoided cost rates and not mandate use of the combined cycle combustion turbine as the combined cycle may not be the electric utility's next avoided or avoidable resource. If a state chooses to use another resource, then it should demonstrate similar factors as those outlined by the Commission for the use of the combined cycle combustion turbine.

The above proposals are not new, but their inclusion in the Commission's regulations will provide certainty to states. More than a dozen years ago, the Oregon Public Utility Commission adopted a Market Hub price-based approach for as available QFs. It held that "as available QFs shall receive day-ahead non-firm market index rates for on-peak and off-peak energy based on the appropriate market index and market hub(s)."[83] It found that doing so was "consistent with federal PURPA law and generally consistent with OAR 860-029-0080(4), which bases avoided

price or that incorporates prices at more than one market hub located in the region, when such prices represent standard pricing practice in the region where the purchasing electric utility is located.").

[81] *Id.* at P 59.

[82] *Id.*

[83] *In the Matter of Pub. Util. Comm'n of Oregon*, No. 07-360, 2007 WL 2413015 (Aug. 20, 2007).

cost rates for non-firm QFs on contemporary avoided costs for non-firm energy."[84] Similarly, using a proxy unit and market gas prices at the time of delivery likely is not a new approach to determining as-available avoided costs.[85] The Florida Public Service Commission has used a similar method in the past and explained that:

> TECO uses a production costing methodology similar to FPL's to determine as-available energy costs. TECO's tariff also describes how TECO will estimate the as-available block size, calculate incremental fuel costs, determine incremental operating and maintenance costs, and account for transmission losses.[86]

Thus, once again, the Commission's actions here simply confirm the authority of states to use options that some states already were using and does not prohibit other approaches which accurately reflect the utility's avoided cost.

3. The Commission appropriately allows States to use forecasted rates or allow rates to vary during the contract term.

First, EEI supports the Commission's proposal to add a new option in section 292.304(d)(1)(iii) of its regulations confirming that states have the flexibility to set energy rates based on forecasted estimates of the stream of revenue flows during the term of a QF contract.[87] There is a misperception that the Commission's proposal to add this option is novel. As explained by the Commission, this proposal would confirm that a state may "rely on market estimates of forecasted energy prices at the times of delivery over the anticipated life of the contract – such estimates are commonly referred to as a forward price curve – to develop a fixed

[84] *Id*.

[85] Certainly, the approach has been used to determine energy prices in firm QF contracts. In the *Winding Creek* case, the court noted that the "Standard Contract offers an avoided-cost rate, calculated using a six-variable formula. However, three of the six variables (burner tip gas price, market heat rate, and a location adjustment factor) are impossible to determine at the time of contracting." *Winding Creek*, 932 F.3d at 864.

[86] *In Re: Planning Hearings on Load Forecasts Generation Expansion Plans, & Cogeneration Prices for Florida's Elec. Utilities*., 92 FPSC 3:202 (Mar. 10, 1992).

[87] NOPR at P 61.

energy rate component for that contract when such estimates reflect the purchasing electric utility's avoided costs."[88]

The Commission's proposal is again nothing new. Several years ago, the Commission and a federal district court both found that the Connecticut Public Utility Regulatory Authority could set avoided cost rates based on a forecast of future avoided costs. "The FERC concluded that 18 CFR §292.304(d)(2)(ii) requires that even restructured states like Connecticut must offer a contract that forecasts avoided costs at the time the contract is executed.[89] The U.S. District Court decided similarly for Massachusetts."[90] The Commission did not rule that any particular form of forecasting was either mandated or was unacceptable. Similarly, in South Dakota, a hybrid avoided cost methodology relies on forecasts of projected prices:

> [T]he Commission finds that the 'hybrid method' or combination method employed by NWE of using forecasted avoided incremental baseload costs for energy supplied to NWE from such resources and projected market prices for energy supplied to NWE from such resources most closely matches NWE's actual avoided costs.[91]

The Commission's clarification that energy rates may be fixed for the term of the contract also ensures that states have the tools necessary to structure contracts that are in the best interest of customers.[92] During the June 2016 Technical Conference, Idaho Commissioner Kristine Raper illustrated the need for the states to have flexibility. Idaho is using this flexibility to balance their responsibilities under PURPA with customer needs. Commissioner Raper stated:

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[88] *Id.*

[89] *Windham Solar LLC & Allco Fin. Ltd.*, 157 FERC ¶ 61,134 at P 5 (2016) ("[T]he Connecticut Authority must recognize that a legally enforceable obligation exists and calculate the appropriate forecasted avoided cost rate pursuant to section 292.304(d)(2)(ii) of the Commission's regulations.").

[90] *Allco Renewable Energy Ltd. v. Mass.Elec. Co.*, 208 F. Supp. 3d. 390 (D. Mass., 2016), at 395 ("National Grid has a direct obligation under federal law to purchase energy at the *long-run forecasted rate*.").

[91] *Oak Tree Energy LLC*, No. EL11-006, 2013 WL 1337288 (S.D. PSC Feb. 21, 2013).

[92] NOPR at P 62.

> So, as you heard at length this morning, the Idaho PUC recently reduced PURPA contract lengths to two years in order to correct the disparity. We didn't reduce contract lengths to kill PURPA. We did it to allow periodic adjustment of avoided cost rates. And in all other ways, these contracts are functionally equivalent to the 20-year contracts that those QFs had prior to [our reduction of the contract length to two years]. They become part of the resource stack once they begin generating energy. They establish their entitlement to capacity. They can renew indefinitely because of the mandatory purchase obligation. The only thing that this changes is the avoided cost rate so that at incremental opportunities, it can be corrected to actually reflect the avoided costs that the utility is incurring by accepting the QF resource. And this is so that rate-payers are not harmed.[93]

Second, EEI supports the Commission's proposal to revise section 292.304(d) of the PURPA regulations to permit a state to limit a QF's option to elect to fix at the outset of a LEO the energy rate for the entire length of its contract. It is appropriate to allow the state to require QF energy rates to vary during the term of the contract. Significantly, the avoided *capacity* costs, if applicable, would still be calculated and fixed at the time the LEO is incurred.[94] This change appropriately reflects the changes in the market. As noted in the Concentric report, technology costs continue to decline.[95] In contrast, relying on some avoided cost methods, such as the costs of a proxy unit at a fixed point in time, may result, and have resulted, in the over-estimation of future energy prices, leaving customers saddled with uneconomic PURPA contracts. The forecast approach helps ensure that states are able to take advantage of declining costs of technology and increased access to renewable resources so that rates for customers are just and reasonable.

[93] Transcript of Technical Conference on Implementation Issues Under the Public Utility Regulatory Policies Act of 1978, Docket No. AD16-16-000, at 143:3-18 (June 29, 2016).

[94] NOPR at PP 66 -67.

[95] *See e.g.,* Concentric at 2 (citing Lazards Analysis). The International Monetary Fund has found that, between 2009 and 2017, prices dropped 76 percent for solar panels and 34 percent for turbines, making them competitive alternatives to fossil fuels and more traditional low-carbon energy sources, such as hydropower and nuclear. *See* International Monetary Fund, Falling Costs Make Wind, Solar More Affordable (Apr. 26, 2019), https://blogs.imf.org/2019/04/26/falling-costs-make-wind-solar-more-affordable/.

In Order No. 69, the Commission gave QFs the option to have avoided costs set at the time the LEO was incurred because it believed that the over and under estimations would balance out over time.[96] This has not been the case as the avoided costs rates have not kept up with declining technology and market costs. In its report, Concentric found that:

> The avoided cost rates in the sample of solar and wind QF contracts we reviewed generally exceeded rates that are realized in competitive markets for solar and wind energy. We also found that trends in solar QF contracts did not reflect underlying cost trends because solar installation costs declined far faster than the administratively determined QF rates. We estimate that utilities and, in the end, customers overpaid in the approximate range of $150.7 million and $216.2 million per year under the QF solar and wind contracts. Accounting for the full term of the solar and wind QF contracts raises the total overpayment estimate to between $2.7 billion and $3.9 billion.[97]

As noted by the Commission, this clarification will help ensure that the variable energy rate more accurately reflects the electric utility's avoided cost so that rates for customers are just and reasonable.[98] This is important for states, especially those in RTO/ISO markets, that elect to have the avoided cost rate set at LMP. The Commission states that it does not anticipate that this change will negatively affect a QFs ability to obtain financing.[99] As discussed in more detail in section IV.B., EEI agrees.

4. The Commission appropriately clarifies that States may use competitive solicitations to set avoided energy and/or capacity prices.

The Commission proposes to permit states the flexibility to set avoided energy and/or capacity rates using competitive solicitations (i.e., Requests for Proposals ("RFPs")), conducted

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[96] Order No. 69 at 12224.

[97] Concentric at 20.

[98] NOPR at P 68.

[99] *Id.* at P 69.

pursuant to appropriate procedures.[100] The fact that competitive solicitations may be used to set avoided costs is an idea nearly as old as PURPA.

In Order No. 69, the Commission found that, "while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load."[101] The Commission also recognized the challenges associated with estimating future avoided costs and found that in, the long run, the over and under estimations would equal out.[102] In 1983, the Commission undertook an examination of state avoided cost methodologies, and "acknowledged the difficulty of administratively determining avoided cost and setting avoided cost rates, and noted that bidding was an alternative that promised greater efficiency in setting avoided cost rates."[103] The Commission later proposed regulations to guide state commission bidding processes, but withdrew them, noting that "well over half the states [that] now use competitive bidding to one degree or another in setting avoided cost rates."[104]

EEI appreciates and supports the Commission's proposal to revise section 292.304 of its PURPA regulations to "permit a state the flexibility to set avoided energy and/or capacity rates using competitive solicitations (i.e., RFPs), conducted pursuant to appropriate procedures."[105] The Commission provides guidance to the states on the bidding process to help ensure that RFPs are conducted in a fair and non-discriminatory manner. This serves to benefit QFs, as compared

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[100] *Id.* at P 82.

[101] Order No 69 at 12,219.

[102] *Id.* at 12,224.

[103] *Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities*, 84 FERC ¶ 61,265, at P 3 (1998) (order terminating proceeding).

[104] *Id* at P 6.

[105] NOPR at P 82.

to the prior regulations, which simply implicitly permitted solicitations. The factors to be considered in establishing an RFP include:

> (a) an open and transparent process; (b) solicitations should be open to all sources to satisfy that purchasing electric utility's capacity needs, taking into account the required operating characteristics of the needed capacity; (c) solicitations conducted at regular intervals; (d) oversight by an independent administrator; and (e) certification as fulfilling the above criteria by the state regulatory authority or nonregulated electric utility.[106]

EEI supports this guidance as it will help the states implement safeguards to ensure that the state implemented procurement process is conducted in a non-discriminatory manner. This level of guidance from the Commission is sufficient and EEI agrees that the Commission should not provide detailed criteria governing the use of RFPs as the states are in the best position to tailor the RFP process to their needs.[107]

Consistent with the Commission's intent to provide flexibility to the states, EEI supports the Commission's proposal for a state to allow an RFP to be used as the exclusive vehicle for acquiring QF capacity. Competitive processes benefit from robust participation, and such participation should be encouraged to yield the most cost-effective generation solutions. If QFs are allowed to opt out of a competitive process, but later take advantage of the pricing determined in that process, the result would be higher prices and excess capacity as the amount of capacity needed to serve load would have been procured in the competitive solicitation. Additional guidance is not necessary to mandate or otherwise prescribe under what circumstances an RFP can be used as a utility's exclusive vehicle for acquiring QF capacity.[108]

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[106] *Id.* at P 87.

[107] *Id.* at P 86. It is worth noting that the Solar Energy Industries Association also supports competitive processes to procure renewable resources. See Supplemental Comments of the Solar Energy Industries Association, Docket No. AD16-16-000 (Aug. 28, 2019).

[108] NOPR at P 88. ("[T]he Commission seeks comment on whether it should provide further guidance on whether, and under what circumstances, an RFP can be used as a utility's exclusive vehicle for acquiring QF capacity.").

5. The Commission should clarify that states may, but are not required to, take into account state procurement policies when determining avoided costs.

Consistent with the Commission's clear guidance that states have the discretion to determine avoided cost, the Commission should clarify in any final rule that states may, but are not required to, adopt avoided cost rate setting methodologies that take into consideration state procurement policies. Many states have adopted renewable portfolio standards and other clean energy procurement requirements. In 2010, the Commission determined that such state policies could be considered when calculating avoided costs and still comply with PURPA.[109] However, the Ninth Circuit recently interpreted the Commission's guidance on this matter as mandating that a state must consider state policies when calculating avoided costs.[110] In light of this decision, states and utilities in the Ninth Circuit are now potentially subject to a new requirement in determining avoided costs. However, this requirement is not set forth in the Commission's PURPA regulations and appears to contradict past Commission guidance that provided wide discretion to states. Moreover, the interpretation arguably is not binding on states outside the Ninth Circuit, such that differing states are subject to differing requirements under one set of regulations. This rulemaking expands the methodologies that are expressly permissible for states to utilize in order to comply with PURPA. Consistent with that objective, the Commission should add clarifying language that "a state <u>may</u>, but is not required to, take into account state procurement policies" when determining avoided costs. This will give all parties clarity on the Commission's guidance on this matter and minimize future disputes.

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[109] *Cal. Pub. Util. Comm'n,* 133 FERC ¶ 61,059, at P 26 (2010) ("[I]n determining the avoided cost rate, just as a state *may* take into account the cost of the next marginal unit of generation, so as well the state *may* take into account obligations imposed by the state that, for example, utilities purchase energy from particular sources of energy or for a long duration. Therefore, the CPUC *may* take into account actual procurement requirements, and resulting costs, imposed on utilities in California.").

[110] *CARE v. CPUC*, 922 F.3d at 938 ("Where a state has an RPS and the utility is using a QF's energy to meet the RPS, the utility cannot calculate avoided costs based on energy sources that would not also meet the RPS.").

B. The Commission's Proposal Will Still Enable QFs to Obtain Financing.

Both the NOPR and Commissioner Glick's dissent discuss the ability of a QF to get financing if the Commission clarifies that fixed prices long-term contracts are not required.[111] This issue is a red herring as PURPA does not require that this Commission or the states implement regulations that guarantee a QFs ability to obtain financing for their project. As previously discussed, Congress intended QFs to be treated similarly to merchant generation and simply required QFs to have non-discriminatory access. Since QFs do not have the oversight or regulatory responsibilities that electric utilities have, it was not expected or intended that they be treated the same as electric utilities.

In any case, where capacity is needed, QFs that are being constructed primarily for market purposes (as opposed to serving their own load) and thus require third-party financing, will still be able to obtain financing if the Commission adopts the proposals in the NOPR. Throughout the NOPR, the Commission simply clarifies that there are options in addition to those currently being used by states to determine avoided costs. A QF developer will still be able to obtain financing under any of the options provided by the Commission, provided it can build a cost-efficient plant that can profit at an avoided cost rate. The Commission accurately noted that QFs would still be able obtain financing if a state sets avoided cost through the use of LMP, Market Hubs, the marginal price of generating energy by a certain generation technology type, competitive procurement, or forecasted energy prices—all of which provide reasonable estimates of future energy rates.[112] Moreover, should a state incorporate this reform into its own PURPA regulations or guidance, QFs still may enter into bilateral contracts outside of PURPA

[111] *See, e.g.*, NOPR at P 78; Commissioner Glick Dissent at P 9.

[112] *See* NOPR at P 71.

that lock in negotiated fixed energy prices. QFs and non-QFs have obtained financing through such contracts and there is no basis for assuming QFs will not be able to going forward.

There has been significant growth in renewable generation and most of the renewable generation being provided today is being provided by independent power producers. These projects are able to get financing through markets and competitive procurements without the certainty of the mandatory purchase obligation under PURPA that QFs enjoy. The requirement that electric utilities must purchase the energy generated by the QF provides a significant additional benefit to QFs for financing purposes. With the growth of markets and increasing participation by independent power producers, financial tools are available today that were not available when Congress enacted PURPA in 1978 and even since the 2005 amendments. Today, merchant power plants may be developed and financed using a variety of hedging and risk management tools, such as commodity hedges, that lock in cash flows and facilitate debt financing or project financing among others. Having a fixed capacity rate, as proposed by the Commission, coupled with the electric utility's mandatory purchase obligation under PURPA will also help QFs obtain financing. Accordingly, there a number of ways to achieve successful project financing today and the lack of a fixed price contract should not preclude QFs from obtaining financing for their projects.

C. The Commission Provides Needed Clarification on the Legally Enforceable Obligation.

Commission regulations currently allow a QF to choose whether avoided costs are determined at the time of delivery or when the LEO is incurred. As electric utilities seek to maintain reliability and resource adequacy, as well as provide just and reasonable rates for customers, EEI has asked the Commission to provide clarity about what it means to pay avoided

costs at the time the obligation is incurred and to clarify that states could adjust energy rates so that customers are not locked into long-term contracts at above-market rates.[113]

Historically, the Commission held that "[i]t is up to the States, not this Commission, to determine the specific parameters of individual QF power purchase agreements, including the date at which a [LEO] is incurred under State law."[114] In more recent years, the Commission has become somewhat more engaged in opining on the issue of what parameters a state can set for a LEO, even bringing an enforcement case on the issue. The parameters for what constitute a LEO is vague. As demonstrated by the complaint in *Western Water*,[115] some QF owners believe that merely notifying a utility that the QF desires to sell energy to the utility locks in the price for future deliveries, even if a project exists in concept only and may never generate electricity.[116] This type of optionality puts the electric utility at risk as it is not able to reliably plan for its system needs or ensure resource adequacy. It also places customers at significant risk of overpayment for the QF's energy and capacity.[117]

EEI appreciates the Commission providing clarity on the factors that a state should consider in determining when a LEO is established. EEI also supports adding regulatory text to section 292.304(d)(3) of the PURPA regulations to require a QF to demonstrate that a proposed project is both commercially viable and that it has a financial commitment to construct the

[113] *Implementation Issues Under the Public Utility Regulatory Policies Act of 1978,* Post-Technical Conference Comments of the Edison Electric Institute, Docket No. AD16-16-000 at 10-11 (Nov. 7, 2016) ("EEI Comments").

[114] *Grouse Creek Wind Park, LLC*, 142 FERC ¶ 61,187, at P 41 (2013) (quoting *W. Penn Power Co.*, 71 FERC ¶ 61,153, at 61,495 (1995).

[115] *Western Water and Power Production Limited LLC (Western Water),* Notice of Petition for Enforcement, Docket Nos. EL17-17 and QF11-516 (Nov. 7, 2016) (*Western Water*).

[116] *See, e.g., Va. Elec. and Power Co.*, Order Denying Application to Terminate Mandatory Purchase Obligation, Docket No. QM15-1-000, at PP 25-26 (Apr.16, 2015).

[117] Supplemental Comments of Edison Electric Institute, Docket No. AD16-16-000, Attachment A, 7 (June 25, 2018) ("EEI Supplemental Comments").

project pursuant to state determined criteria to be eligible for a LEO.[118] The NOPR's proposed revisions to the PURPA regulations to require a demonstration of commercial viability and financial commitment will provide much needed clarity regarding when a QF is entitled to a LEO, which will reduce litigation. Moreover, the Commission's proposal to require a QF to demonstrate that a project is "viable" is also consistent with precedent in various state and federal courts.[119]

Furthermore, EEI agrees with the Commission that states should retain authority to develop objective and reasonable criteria to determine commercial viability.[120] Some parties have asserted that the Commission should establish a federal test for when a LEO is established, but doing so would contravene the role of the states that PURPA intended. Additionally, except for the clarification requested below, EEI generally supports the list of non-exhaustive prerequisites that a state may adopt to allow a QF to demonstrate commercial viability and financial commitment. Additional prerequisites do not need to be identified by the Commission.[121]

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[118] NOPR at P 140.

[119] *E.g., Power Resource Group Inc. v. Pub. Util. Comm'n Tex.*, 422 F.3d 231 (5th Cir. 2005) (upholding rule adopted by the Public Utility Commission of Texas that a LEO cannot be created if the QF cannot provide the power within 90 days); *S. River Power Partners, LP v. Penn. Pub. Util. Comm'n*, 696 A.2d 926 (Pa. Cmwlth. 1997) (holding that project was not viable where developer had not, among other things, applied for or gained any of the necessary permits for the project); *Mid-South Cogeneration, Inc. v. TVA*, 926 F. Supp. 1327, 1337 (E.D. Tenn. 1996) (holding that a developer was not eligible to receive a LEO whether the facility did not exist); *Appeal of Pub. Serv. Co. of N.H.*, 539 A.2d 275, 130 N.H. 285 (1988) (holding that QF established viability where cogenerator acquired, among other things, sufficient permits for construction and operation of the project); *Great Divide Wind Farm 2, LLC*, v. *Becente Aguilar*, *et al*., 2019 WL 5847060, at *29-30 (D.N.Mex. 2019) (finding the New Mexico commission's "ready-to-interconnect" requirement to establish a LEO consistent with PURPA and FERC's regulations). *See also Exelon Wind 1, L.L.C., et al., v. Nelson, et al.* 766 F.3d 380 (5th Cir. 2014) (upholding Texas commission's challenging the PUC's requirement that only QFs that generate "firm power" were eligible to sell power through a legally enforceable obligation).

[120] *See* NOPR at P 140.

[121] *See id*. at P 141.

Although EEI largely supports the NOPR's proposals with respect to LEOs, EEI requests that the Commission revisit its current policy concerning states' ability to require an executed interconnection agreement as a condition precedent for a QF to obtain an LEO. In the NOPR, the Commission states that such prerequisites "[do] not satisfy PURPA's requirement that the Commission prescribe rules as necessary to encourage the development of QFs."[122] The Commission has further explained, within the context of evaluating a specific standard promulgated by the Montana Public Service Commission, that requiring an executed interconnection agreement "allows the utility to control whether and when a legally enforceable obligation exists—e.g., by delaying the facilities study or by delaying the tendering by the utility to the QF of an executable interconnection agreement."[123]

The Commission's policy regarding executed interconnection agreements, although well-intentioned, does not consider that the Commission requires electric utilities to facilitate the generator interconnection process in a manner that is just and reasonable and not unduly discriminatory or preferential.[124] These requirements are also included in the Commission-approved open access transmission tariffs of either the electric utility or the applicable RTO/ISO. The Commission's policy also does not recognize that QFs have multiple avenues to seek relief, be it from the Commission, the state authority, or through the courts. The Commission's concerns regarding an electric utility delaying facilities studies or withholding an executed interconnection agreement would also seem to be misplaced within the context of organized wholesale electricity markets, where the RTO or ISO is responsible for facilitating the

[122] *Id.* at P 135.

[123] *FLS Energy, Inc.*, 157 FERC ¶ 61,211, at P 23 (2016).

[124] *See generally Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043 (2018); *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 (2003).

interconnection process. Finally, an executed (state) interconnection agreement helps to demonstrate a QFs viability by providing, among other things, information on whether (i) the developer has conducted an appropriate level of planning and design necessary for interconnection studies to be conducted, (ii) the QF can be interconnected without excessive transmission system costs on the date the QF requested and that was relied upon in the calculation or determination of its avoided cost price, and (iii) that the QF operator and the interconnection provider have agreed upon operating requirements for the QF.

In the event the Commission is unwilling to reconsider its prior guidance on a state's discretion to require an executed interconnection agreement as a condition for a QF obtaining a LEO, EEI requests that the Commission, at a minimum, clarify its statement in paragraph 141 of the NOPR that suggests the QF's mere filing of an interconnection application could be evidence of commercial viability sufficient to establish a LEO. The mere filing of an interconnection application provides nothing to the utility in terms of confirming viability of a project, particularly confirming a project's ability to come on-line on the date the QF has represented for purposes of establishing the QF's avoided cost price. A state should be permitted to require, as a condition to LEO formation, that a QF provide at a minimum one interconnection study that reasonably supports the assumptions (e.g., commercial operation date) that underlie the calculated or otherwise established avoided cost price.

D. The Commission Appropriately Recognizes That Utilities in Retail Choice States Can Match Their Mandatory Purchase Obligations with Supply Obligations.

EEI supports the Commission's proposal to modify section 292.303(a) of its regulations to provide electric utilities relief from the mandatory purchase obligation to the extent that their supply obligations are reduced by a state retail choice program.[125] The proposed revision reflects

[125] NOPR at P 89.

the changes that have occurred in the market since Congress enacted PURPA and it will result in just and reasonable rates, as electric utilities are not required to purchase energy for load that they are not serving.

Prior to retail restructuring, electric utilities were responsible for serving the load within their service territories. In the 1990s, many states restructured their electricity regulatory models to introduce retail choice that allowed distribution retail electric customers to choose to purchase energy from an alternate electricity supplier rather than from their local utility. Many states also required their traditional electric utilities to divest their electric generation. Thus, restructuring removed such utilities' respective obligations to serve native load. However, they were required to continue to serve as the Provider of Last Resort ("POLR") and serve customers, usually through a competitive solicitation process. These contracts were generally one-year or less in duration to enable customers to easily move to retail suppliers and to prevent electric utilities from being stuck with long-term contracts for a shifting customer base.

The Commission's current regulations therefore distort the competitive playing field and undermine the market-based system adopted by states to restructure their retail electricity markets. Based on these changes that are attendant to restructured markets, the purchase of QF power no longer reflects the electric utility's actual avoided costs. The Commission has previously recognized this conflict and expressed "concern that the mandatory QF purchase obligation under PURPA in conjunction with administratively avoided cost rates may be inconsistent with the operation of an effective competitive market."[126]

Accordingly, EEI agrees that the Commission's proposal to limit the length of the electric utility's PURPA contract to match the POLR solicitation term more accurately reflects the

[126] *Cogen Lyondell, Inc.*, 95 FERC ¶ 61,243 at 61,838 (2001).

electric utility's avoided cost obligation in a restructured market.[127] This is consistent with Commission precedent providing that an electric utility should not have to pay for capacity that is not needed.[128]

E. The Proposed Changes to the Evaluation of Whether QFs Are Separate Facilities Are Appropriate.

1. The Commission's proposed changes to create a rebuttable presumption are appropriate.

PURPA defines a small power production facility as:

> [A] facility which is an eligible solar, wind, waste, or geothermal facility, or a facility which (i) produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, geothermal resources, or any combination thereof; and (ii) has a power production capacity *which, together with any other facilities located at the same site* (*as determined by the Commission*), *is not greater than 80 megawatts*.[129]

The interpretation of "same site" is determined by the Commission. There is nothing in the statute that prevents the Commission from modifying its interpretation of the term "same site."[130]

Currently, section 292.204(a) of the PURPA regulations provides that small power production facilities are considered to be at the same site if they are located within one mile of each other, use the same energy resource, and are owned by the same person(s) or

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[127] *See* NOPR at P 114 (proposing revision to § 292.303(b)).

[128] *Id.* at P 33 n.58. Moreover, in making avoided cost determinations, some states have determined that requiring an electric utility to purchase capacity that it does not need (e.g. the QF would not displace the utility's capacity purchases) would be contrary to the public interest. *See, e.g. In The Matter of Idaho Power Company's Petition To Modify Terms and Conditions of PURPA Purchase Agreements*, No. 33419, 2015 WL 6958997, at 15 (Idaho P.U.C.); *accord Hydrodynamics, Inc., et al.*, 146 FERC ¶ 61,193 at P 35 (2015). Given that the POLRs in retail restructuring states almost universally do not need additional capacity given the structure of their markets, it would be reasonable for the avoided costs for their capacity to be set at zero.

[129] 16 U.S.C. § 796(17)(A) (emphasis added).

[130] There is broad support for reform of the one-mile rule. *See* Transcript of Comments of Rep. Pallone, Legislation Addressing LNG Export and PURPA Modernization, House Energy Subcommittee (Jan. 19, 2018) ("I am not completely opposed to updating PURPA. The part of Mr. Walberg's bill dealing with the so-called One-Mile Rule, which many claim has encouraged the segmentation of PURPA projects that would otherwise not qualify under the law, that merits attention."); NOPR, Commissioner Glick Dissent at P 23 ("I agree that it is time to address the 'one mile' rule.").

its affiliates. This regulatory provision is commonly referred to as "the one-mile rule" and is used to calculate the size of a facility and to determine when projects are indeed separate or should instead be considered part of one facility. In Order No. 69, the Commission established the affiliation requirements and stated that facilities are considered to be "located at the same site as the facility for which [QF] qualification is sought if the facilities are located within one mile of the facility for which qualification is sought."[131] The Commission has stated that the one-mile rule is an irrebuttable presumption – facilities within one mile are at the same site and facilities more than a mile apart from each other are not.[132] As the markets have evolved and as increasingly sophisticated players have entered the market, the current rule has allowed gaming in two ways: (1) QFs are finding creative ways around the affiliation rules, and (2) the one-mile requirement can be evaded as resources with common ownership, financing, and even operation are located just slightly over one mile from each other so as to qualify for the 80 MW threshold in the statute.

For example, in *Northern Laramie Range Alliance*, the applicant filed for QF self-certification of two 48.6 MW projects that were part of a single wind farm with one site permit and that shared a point of interconnection.[133] Because the projects were located more than one mile apart, each project was certified as an individual QF.[134] In *Beaver Creek II*, where two projects were potentially less than one mile apart, the Commission certified each of the projects as QFs because their owners held less than 10 percent stock in the same parent, even though that parent's subsidiary would administer a Construction Management and Administrative

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[131] 18 C.F.R. § 292.204(a)(2)(i-ii). *See also* Order No. 69.

[132] NOPR at P 96.

[133] *Northern Laramie Range Alliance*, 138 FERC ¶ 61,171 (2012).

[134] *Id.*

Management Services Agreement with costs shared among four QFs and all four QFs owned shares in the same radial line.[135] Thus, as the Commission has previously recognized, the one-mile rule is indeed "arbitrary."[136]

Accordingly, EEI supports the Commission's proposal to amend sections 292.204(a) and 292.207 of the PURPA regulations "to allow entities challenging a QF certification to show that affiliated small power production facilities more than one mile apart and less than ten miles apart, actually are part of a single facility, and not separate facilities; the presumption, in other words, would be a *rebuttable* presumption for facilities over one mile apart and less than ten miles apart."[137] By creating presumption in favor of the QFs, the Commission is merely providing an opportunity for stakeholders to bring to the Commission's attention instances in which the regulation is being gamed or manipulated so that developers may receive the benefits of QF status even when such status is unwarranted. The change protects competition by ensuring those non-QF independent power producers in the utility-scale solar business are not unfairly subject to FPA regulatory requirements that other developers seek to escape through PURPA by using the one-mile rule in a manner never intended.

While providing an opportunity for due process for stakeholders, the NOPR provides additional certainty and safeguards for QFs by allowing them to provide additional information in their QF certification filing to pre-emptively defend against charges that the facilities are separate facilities[138] and requiring challengers to make a *prima facie* demonstration that facility does not meet the requirements for a QF.[139] For this proposal to be successful, it is critical that it

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[135] *Beaver Creek II*, 160 FERC ¶ 61,052 (2017).

[136] *See Windfarms, Ltd.*, 13 FERC ¶ 61,017 (1980).

[137] NOPR at P 94.

[138] *Id.* at P 103.

[139] *Id.* at P 104.

only apply when notice has been actually served on the interconnecting and purchasing utilities, in accordance with 18 CFR 292.207(c), and that evidence of the factors used to show whether a project is a single facility is sufficiently provided under such notice (i.e., FERC Form 556). This proposal provides a QF with more certainty to defend against possible challenges and appropriately puts the burden on the challenger. The NOPR also provides a list of factors that may be relevant in rebutting the presumption.[140] This provides the QF not only with the types of information that could be included in their certification, but also what the challenger would have to show.

The physical and operational characteristics listed in the NOPR that could be used to defend or rebut a challenge are appropriate.[141] The Commission should clarify that the list is not exhaustive so that stakeholders challenging a certification application have the opportunity to demonstrate other factors as appropriate. The Commission should not prioritize, delineate, or otherwise weigh the factors as each case should be decided on its merits and fact patterns will vary.[142] EEI also supports the Commission's proposal to use the definition of affiliate provided in section 35.36(a)(9) of the Commission's regulations. Under this definition, owning, controlling, or holding with power to vote, less than 10% of the outstanding voting securities of a specified company creates a rebuttable presumption of lack of control. The non-exhaustive list of physical and operational characteristics outlined by the Commission to show that facilities are not separate facilities is also appropriate to show that entities are affiliates.

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[140] *See id.* at P 105.

[141] *Id.*

[142] *Id.* ("The Commission solicits comments on whether the Commission should rely on some or any of these factors, or other factors, or whether the various factors should be considered together and weighed.").

2. The proposed definition of electric generating equipment should be further clarified.

Under the one-mile rule, the measurement used to determine whether facilities are part of a single facility or separate facilities is the distance between the electrical generating equipment of each facility.[143] The NOPR proposes defining "electric generating equipment" to refer to:

> [A]ll boilers, heat recovery steam generators, prime movers (any mechanical equipment driving an electric generator), electrical generators, photovoltaic solar panels and/or inverters, fuel cell equipment and/or other primary generation equipment used in the facility, *excluding equipment for gathering energy to be used in the facility*.[144]

The definition does not reference electric storage resources (i.e., batteries or pump storage) and the NOPR does not contain any discussion on whether electric storage resources should be included in the definition. In light of other Commission orders and pending dockets, additional clarification is needed.

In Order No. 845, the Commission recently amended the definition of "Generating Facility" in the *pro forma* OATT to explicitly include storage.[145] Order No. 845 states that:

> **Generating Facility** shall mean Interconnection Customer's device for the production <u>and/or storage for later injection</u> of electricity identified in the Interconnection Request, but shall not include the interconnection customer's Interconnection Facilities.[146]

The Commission explained that "the purpose of this definition change is to make clear that electric storage resources with a capacity of more than 20 MW may interconnect pursuant to the *pro forma* LGIP and *pro forma* LGIA."[147] The definition, Generating Facility, is implicated in

[143] 18 CFR 292.204(a)(2)(ii).

[144] NOPR at P 108 (emphasis added).

[145] *Reform of Generator Interconnection Procedures and Agreement*, Order No. 845, 163 FERC ¶61,043 (2018), *order on reh'g*, Order No. 845-A, 166 FERC ¶ 61,137 (2019).

[146] *Id.* at Appendix C, Article 1.

[147] *Id.* at P 279.

all OATT interconnection modeling, studies and agreements, and therefore, is implicated in all QFs with OATT based interconnections. The Commission made an identical definitional change in Order No. 792 with respect to the *pro forma* Small Generator Interconnection Procedures and the *pro forma* Small Generator Interconnection Agreement.[148]

Not providing clarification on how storage should be treated in the definition of "electric generating equipment" could cause confusion when applying the one-mile rule. Section 292.204(a)(2)(ii) of the PURPA regulations states that to measure one mile, "the distance between facilities shall be measured from the electrical generating equipment of a facility." In the NOPR, the Commission proposes measuring the distance between the nearest "electrical generating equipment" of any two facilities such that, for the facilities to be considered irrebuttably separate, all such equipment of one QF must be at least ten miles away from all such equipment of another QF.[149] Additionally, item 8a of Form No. 556 requires that the applicant identify any facilities with electrical generating equipment within one mile of the instant facility's electrical generating equipment.[150] If the Commission does not provide clarity regarding whether electric storage resources are included in the definition of Generating Facility, then there will likely be inconsistency in how parties apply the one-mile rule.

Moreover, the Commission explicitly excluded gathering equipment from the explanation of electrical generating equipment in Order No. 70, in which the Commission stated:

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[148] *See Small Generator Interconnection Agreements and Procedures*, Order No. 792, 145 FERC ¶ 61,159, at P 228 (2013).

[149] NOPR at P 72.

[150] *Id.* at P 73.

> The comments noted that some facilities may include equipment for gathering energy to be used in the facility which may extend up to a number of miles from the generating facility. The Commission believes that the one-mile limit should be measured from the generating facilities.[151]

However, Order No. 70 did not define nor explain what a gathering facility is. In 1980 (when Order No. 70 was issued), battery storage was not utilized in the energy industry as an electric storage resource. Additionally, energy in an electric storage resource is not energy to be used "in" the facility, but rather energy to be used instead of operating a facility.[152] Based on the characteristics of battery storage, it appears that battery storage is not the same as a gathering facility. EEI requests that the Commission confirm this interpretation.

Since the electric storage resource located at the Generating Facility site is part of the Generating Facility for all applications and contracts pursuant to the OATT, the electric storage resources also should be considered part of the "facility" for QF distance measuring purposes. EEI respectfully requests that the Commission clarify its regulations to include electric storage resources for purposes of applying the one-mile rule, but continue to exclude gathering equipment. EEI proposes that the Commission clarify how to measure the distance between two or more facilities as follows to accommodate this inclusion:

> 18 C.F.R. §292.204(a)(2)(ii) - For purposes of making the determination in clause (i), the distance between facilities shall be measured from the electrical generating equipment *or electric storage resources* of the facility for which qualification is sought and the nearest electrical generating equipment *or electric storage resources* of the other facility using the same energy resource and owned by the same person(s) or its affiliates.

Furthermore, including "electric storage resources" in the definition of a Generating Facility is in line with the statutory language of PURPA and Commission precedent. A QF is:

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[151] Order No. 70 at 30,943.

[152] Section 35.28(b)(9) of the Commission's PURPA Regulations defines *electric storage resource* as a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid.

> [A] facility which is an eligible solar, wind waste, or geothermal facility, or a facility which (i) produces electric energy solely by the use, *as a primary energy source*, of biomass, waste, renewable resources, geothermal resources, or any combination thereof; and (ii) has a power production capacity, which, together with any other facilities located at the same site is not greater than 80 megawatts.[153]

As such, Commission precedent recognizes that electric storage equipment does not independently satisfy the definition of a "primary energy source" and that the Commission must therefore "look to the source of energy as the ultimate primary energy sources of the facility."[154] While electric storage equipment can certainly be a component of a QF, the pairing of electric storage equipment with a "primary energy source," both of which are located on a single site, should not be permitted to qualify as a QF if the rated capacity of all the equipment combined exceeds 80 MW. To permit such facilities to qualify as a QF would conflict with the plain language of PURPA and Congressional intent. It also would enable gaming and constrain competition by reducing or eliminating opportunities for non-PURPA renewables and other carbon-free generation.

As such, EEI respectfully requests that the Commission revise 18 C.F.R. §292.204(a)(2)(ii) as proposed above and clarify the definition of electric generating equipment. With this proposed clarification, EEI supports the Commission's proposed definition and its proposal for measuring the distance between any two facilities for purposes of applying the one-mile rule.

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[153] 16 U.S.C. § 796(17)(A) (emphasis added).

[154] *Luz Development and Finance Corp.*, 51 FERC ¶ 61,078 (1990).

3. Changes to FERC Form 556 are needed.

a. The Commission's proposed changes to FERC Form 556 are appropriate.

The NOPR proposed changes to FERC Form 556, which certifies QF status, to accommodate the proposed changes to the one-mile rule.[155] EEI generally supports the proposed changes to Form 556. Specifically, EEI supports the Commission's proposal to modify Lines 8(a) and (b) to require that the applicant specify the distance from the instant facility to each facility listed in the application and to specify how the reported distances were calculated, including identifying the "particular generating equipment and associated geographic coordinates used in calculating the distance(s) between the facility(ies)."[156] Related to this change, EEI supports the Commission's proposed change to item 3c to require all applications, rather than just applications that do not have a street address, to provide geographic coordinates.[157] Providing both of these data points will increase transparency and will assist stakeholders and Commission staff in evaluating whether the requirements of the rule are being met. If this information is not required, stakeholders will have difficulty verifying the information in the application or recreating the measurement. The additional information will also be helpful to electric utilities in the interconnection process.

For similar reasons, EEI also supports the continued inclusion on Line 8(a) of all affiliated QFs and affiliated non-QFs.[158] The requirement to list all affiliates, not just affiliated

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[155] NOPR at PP 111-117.

[156] *Id.* at P 114. ("[W]e seek comment on whether the applicant should be required to identify the particular electrical generating equipment and associated geographic coordinates used in calculating the distance(s) between the facility(ies)").

[157] *Id.* at P 116.

[158] *Id.* at P 115 ("[W]e seek comment on whether we should revise item 8a (existing) and write item 8b (as newly proposed) to require that applicants list only affiliated QFs, or whether there is reason to continue to require all affiliated facilities to be listed.").

QFs, is necessary to verify that the QF is complying with the proposed rule and not creating QFs to benefit from the preferred treatment provided.

b. Additional changes to FERC Form 556 are needed.

Additional modifications to Form 556 are needed to recognize the growth and usage of battery storage. First, changes are needed to Line 7 of the form. As previously noted, a QF is:

> [A] facility which is an eligible solar, wind, waste, or geothermal facility, or a facility which (i) produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, geothermal resources, or any combination thereof; and (ii) has a power production capacity, which, together with any other facilities located at the same site is not greater than 80 megawatts."[159]

In *Occidental Geothermal, Inc.*, while recognizing that "[t]he Conference Report accompanying PURPA indicate[d] that the power production capacity of the facility is its 'rated capacity,'"[160] the Commission stated that it:

> [W]ill consider the "power production capacity" of a facility to be the maximum net output of the facility which can be safely and reliably achieved under the most favorable operating conditions likely to occur over a period of several years. The net output of the facility is its send out after subtraction of the power used to operate auxiliary equipment in the facility necessary for power generation (such as pumps, blowers, fuel preparation machinery, and exciters) and for other essential electricity uses in the facility from the gross generator output.[161]

This interpretation is reflected in Lines 7(a) through 7(g) of Form 556, which require applicants to list the gross power production under the most favorable design conditions and then deduct a variety of losses from the gross power production capacity to get to the net power production

[159] 16 U.S.C. § 796(17)(A).

[160] *Occidental Geothermal, Inc.*, 17 FERC ¶ 61,231 at 61,444 (1981).

[161] *Id.* at 61,445.

capacity.[162] The Commission uses the net power production capacity to determine if a facility should be certified as a QF. The form does not specifically address the inclusion of other resources, such as electric storage, on the same site. With the growth of storage technology and the increased ability of resources to inject more than 80 MW of energy onto the grid, the use of net production capacity may no longer be an appropriate interpretation of power production capacity. Accordingly, the Commission should make changes to Form 566 to require QFs to report the rated capacity, rather than net capacity, of all the resources on the site (e.g., renewable and electric storage).

Second, if the Commission accepts the proposal to include electric storage resources in 18 C.F.R. § 292.204(a)(2)(ii) as discussed above, the same language would need to be included to lines 8(a) and 8(b) of Form No. 556. Specifically, EEI proposes the following change:

> 8(a) – Identify any facilities with electrical generating equipment *or electric storage resources* located within 1 mile of the electrical generating equipment *or electric storage resources* of the instant facility . . . .

A similar change would be required for the new item 8(b), which would cover affiliated facilities whose nearest electrical generating equipment *or electric storage resources* is greater than 1 mile and less than 10 miles from the electrical generating equipment *or electric storage resources* of the instant facility.

F. The NOPR's Proposed Changes to the Self-Certification Process Promote Due Process.

EEI supports the Commission's proposal "to change § 292.207(a) of the PURPA Regulations to allow a party to intervene and to file a protest of a self-certification or self-recertification of a facility without the necessity of filing a separate petition for declaratory order

[162] *See* FERC Form 556 – Certification of QF Status for Small Power Production and Cogeneration Facilities, at 1, 9, *available at*: https://www.ferc.gov/docs-filing/forms/form-556/form-556.pdf.

and without having to pay the filing fee required for a declaratory order."[163] When the Commission first implemented section 201 of PURPA, it provided two paths to QF status: self-certification and Commission certification. There was a fee for Commission certification and no fee for self-certification. QFs that chose the self-certification process submitted a completed Form 556. The Commission reviewed the form, but did not issue an order confirming that the applicant qualified for QF status.[164] Although the Commission docketed the self-certifications, it did not issue notices of the filings. Over the course of time, the Commission revised its certification rules to provide for publication in the *Federal Register* and electronic filing of Form 556. The Commission subsequently revised its notification procedures to eliminate the requirement of publication in the *Federal Register*, but to instead require a QF to provide notice to the affected electric utility and state regulatory authorities.[165] However, the Commission has always required those that wished to challenge a self-certification to file a petition for declaratory order and pay the filing fee, which is currently set at $28,990.[166]

While EEI does not oppose the self-certification process, EEI appreciates the Commission's recognition that, in the interest of due process, stakeholders should be able to respond to an application for self-certification as a QF without undue burdens, including a high filing fee. EEI understands that the Commission created the self-certification process to facilitate certification for QFs and generally supports the process that has been outlined in the NOPR. The proposal allows interested parties to challenge the QF certification if necessary and establishes time frames for timely resolution of the challenge process.

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[163] NOPR at P 148.

[164] *Id.* at P 143.

[165] *Id.* at P 145.

[166] *Id.* at P 146. *See* Federal Energy Regulatory Commission, Filing Fees, Petition for issuance of declaratory order, https://ferc.gov/docs-filing/fee-sched.asp (last updated May 10, 2019).

The ability to challenge is premised on the Commission's requirement that the applicant serve a copy of its self-certification on interested electric utilities.[167] As noted in section IV E,[168] providing effective notice is a key component of the Commission's proposal. In order to ensure compliance, EEI requests that the Commission place this requirement in its regulations and codify its previous response to a frequently asked question, which states:

> QF with a net power production capacity of 500 kW or greater must still provide 90-day notification of its QF status to the local utility to which it connects, even if it is exempt from the Form No. 556 filing requirement. Such notification can be made by a simple written notice or, if the applicant has filed a Form No. 556, by sending the utility a copy of the completed form.[169]

In addition, while EEI appreciates the need for timeframes to provide certainty to QFs, electric utilities should be able to challenge a self-certification outside of the time frames outlined in the NOPR if the completed project is materially different than the project outlined in the notice. This change will ensure that electric utilities have recourse, within the framework proposed in the NOPR, for projects that materially differ from what the applicant represented in the notice, while still allowing for a timely self-certification process.

G. Reducing the 20 MW Threshold to 1 MW In RTO/ISO Markets Appropriately Reflects the Increased Access Available to Smaller Resources.

As discussed in section IV, the Commission's "responsibilities under PURPA are three-fold: (1) to encourage the development of QFs; (2) to prevent discrimination against QFs by incumbent utilities; and (3) to ensure that the resulting rates paid by electricity customers remain just and reasonable and in the public interest."[170] Under EPAct 2005 an electric utility's participation in certain types of markets can meet those goals without the need for a mandatory

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[167] NOPR at P 148.

[168] *See supra* § IV.E.

[169] Federal Energy Regulatory Commission, Frequently Asked Questions, Qualifying Facilities, https://www.ferc.gov/resources/faqs/qf-faqs.asp (last updated Aug. 27, 2019).

[170] NOPR, Commissioner Glick Dissent at P 1.

purchase obligation. Specifically, EPAct 2005 added section 210(m) to PURPA, which provides for termination of the requirement that an electric utility enter into a new contract or obligation to purchase electric energy from QFs if the Commission finds that the QF has nondiscriminatory access to one of three categories of markets defined in section 210(m)(1)(A), (B), or (C). The Commission has found that all of the RTOs/ISOs meet one of the three criteria outlined in section 210(m).[171]

In implementing section 210(m), the Commission found that the existence of an OATT created a rebuttable presumption that QFs greater than 20 MWs have non-discriminatory access to the relevant wholesale market.[172] The regulations allowed electric utilities to terminate their obligations to purchase from QFs above 20 MW, with a showing that they were in a market that the Commission found met the EPAct 2005 requirements. The electric utilities were still required, however, to continue purchasing from QFs 20 MW or smaller, absent a case-by-case determination that the QF had nondiscriminatory access to transmission and capacity and energy markets.[173]

Section 210(m) does not include any QF size threshold for the Commission to terminate an electric utility's mandatory purchase obligation for that QF where the Commission has found that the electric utility participates in one of the three categories of markets defined in section

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[171] *See* 18 C.F.R. §§ 292.309(e)-(g). Pursuant to 18 CFR § 292.310 electric utilities must still file an application with the Commission setting forth the factual basis on which relief is requested including why the requirements in 18 C.F.R. § 292.309 have been met. If the Commission's proposal to reduce the 20 MW threshold is adopted, the Commission should consider waiving the need for a subsequent filing for electric utilities that have already received an exemption for resources over 20 MW.

[172] *New PURPA Section 201(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Final Rule, Order No. 688, 117 FERC ¶ 61,078 (Oct. 20, 2006).

[173] 18 CFR § 292.309 (d)(1).

210(m)(1)(A). Rather, the statute only requires that a QF have non-discriminatory access to such markets.[174] Thus, there is no statutory obligation to retain the current 20 MW threshold.

Regardless of whether the 20 MW threshold was just and reasonable when the Commission first adopted it in Order No. 688, it is no longer just and reasonable given changes in RTO/ISO markets to facilitate the participation of smaller resources. With the increasing opportunities for smaller renewable energy resources to participate in those markets, these resources have non-discriminatory access and, accordingly, electric utilities should no longer be required to purchase electric energy from them. Therefore, EEI supports the Commission's proposal to reduce the 20 MW threshold to 1 MW.[175]

As resource diversity has improved and the markets have evolved, smaller resources—including QFs—are increasingly participating in the RTO/ISO markets. This participation has

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[174] Section 210(m) states in part:

> **OBLIGATION TO PURCHASE:** After August 8, 2005, no electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that the qualifying cogeneration facility or qualifying small power production facility has nondiscriminatory access to—
> **(A)(i)** independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and **(ii)** wholesale markets for long-term sales of capacity and electric energy; or
> **(B) (i)** transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and **(ii)** competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or
> **(C)** wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in subparagraphs (A) and (B).

16 U.S.C. § 824a–3(m).

[175] Contrary to Commissioner Glick' assertion that there is no record evidence on this issue, in post-technical conference and supplemental comments, EEI suggested that the Commission should reduce or eliminate the 20 MW size threshold in sections §292.309(d)(1) and (e) so that QFs are presumed to have non-discriminatory access to the RTO/ISO markets absent evidence to the contrary. *See* EEI Comments at 12-15; EEI Supplemental Comments, Attachment A, at12-13.

been facilitated in part by Commission orders. For example, in Order No. 841, the Commission found that RTOs/ISOs must allow for the participation of electric storage resources as small as 100 kW,[176] finding that "the record shows that all RTOs/ISOs are already accommodating the participation of smaller resources [i.e., as small as 100 kW] in their markets."[177] Similarly, the Commission is currently considering minimum size requirements for the participation of distributed energy resource aggregations in organized wholesale electric markets,[178] having already accepted aggregations of 500 kW in CAISO.[179] More broadly, the Commission has developed additional processes for smaller thresholds of generators.[180] At the same time, the Commission has recognized the improving capabilities of smaller generation resources, eliminating some exceptions provided for small generators in the *pro forma* interconnection agreement.[181] In sum, smaller generation resources (including QFs) are both technically capable of and have the opportunity to provide a wider range of services in the RTO/ISO markets than was the case when the Commission adopted the 20 MW threshold.

Commission policy is not alone in driving increased participation of smaller resources in RTO/ISO markets. To facilitate the participation of diverse and smaller resources, RTOs/ISOs have increasingly adjusted their bidding rules, forecasting, and operations to better accommodate

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[176] Order No. 841 at PP 265-271.

[177] *Id.* at P 267.

[178] *See Participation of Distributed Energy Resource Aggregation in Markets Operated by Regional Transmission Organizations and Independent System Operators* and *Distributed Energy Resources Technical Considerations for the Bulk Power System*, Notice of Technical Conference, Docket Nos. RM18-9-000 and AD18-10-000 (February 15, 2018).

[179] *Cal. Indep. Sys. Operator*, 155 FERC ¶ 61,229 (2016) (conditionally accepting CAISO's tariff revisions to facilitate participation of aggregations of DERs in CAISO's energy and ancillary services markets).

[180] *Small Generator Interconnection Agreements and Procedures*, Order No. 792, 145 FERC ¶ 61,159, (2013) (providing expedited interconnection procedures for facilities up to 5 MW).

[181] *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*, 162 FERC ¶ 61,128 (2018) (requiring small generators to be capable of providing primary frequency response); *Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities*, 156 FERC ¶ 61,062 (2016) (requiring small generators to ride-through low voltage events).

variable resources. The Commission noted this increased access in adopting a 100-kW threshold for storage participation in RTO/ISO markets. Order No. 845-A stated that:

> The Commission further found that the record shows that all RTOs/ISOs are already accommodating the participation of smaller resources in their markets. For example, the Commission stated that the record shows that all RTOs/ISOs already have the modeling and dispatch software capabilities to accommodate the participation of resources that are as small as 100 kW. Specifically, the Commission noted that both PJM and SPP have a minimum size requirement of 100 kW for all resources, and all of the RTOs/ISOs have at least one participation model that allows resources as small as 100 kW to participate in their markets.[182]

Thus, as recognized by the Commission, smaller resources are increasingly participating in the RTO/ISO markets. For example, an examination of the resources participating in PJM Interconnection LLC ("PJM") and Southwest Power Pool, Inc. ("SPP") shows that resources under 20 MW, and even resources under 10 MW, are increasingly participating in the wholesale market.[183] The Commission's proposal will also help ensure that QFs are not granted an undue preference over other resources.

The Commission's proposal to reduce the 20-MW threshold to 1-MW reflects the Commission's finding that the ability of small resource to access the wholesale markets has improved. Additionally, EEI supports the Commission's revision because it will ultimately reduce costs to customers. The proposal will also ensure that QF resources do not have an undue advantage over other resources such as electric storage resources, demand response aggregators, and other small resources seeking to participate in the Commission regulated RTO/ISO markets. The result of applying the current 20-MW threshold is that some customers ultimately pay higher prices for renewable energy than they otherwise would. Some QFs that have access to RTO/ISO

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[182] Order No. 845-A at P 95.

[183] *See* PJM Interconnection LLC, New Services Que, https://pjm.com/planning/services-requests/interconnection-queues.aspx (e.g., demonstrating that PJM's New Services Queue includes over 400 solar generation resources that have a maximum facility output of 20 MW or less); Southwest Power Pool, Inc., Modeling Reports, https://marketplace.spp.org/file-browser-api/download/modeling-reports?path=%2FSL_Station_BusNumber_Turbine_and_FuelType.xlsx.

markets are foregoing the opportunity to participate in those markets and electing to contract with electric utilities under state implemented PURPA programs, which compensate at an above market rate. More often than not, electric customers are finding themselves in this particular quagmire where their electric utility is required to buy energy from a QF at above market rates when that QF has non-discriminatory access to an RTO/ISO market (but instead chose to forego participation in the competitive wholesale markets in favor of obtaining PURPA contracts).

V. CONCLUSION

EEI appreciates the Commission taking a holistic review of its regulations implementing PURPA and the opportunity to submit comments on this important issue. The proposals in the NOPR appropriately fulfill the Commission's obligation to review and update its regulations implementing PURPA to reflect the changes in the market including open access to transmission, greater competition among generators in organized and bilateral wholesale markets, improvements in technology, lower costs of technology, and implementation of state and federal policies favoring renewable resources. These changes have all helped drive changes in the fuel mix so that generation from co-generation and renewable energy resources, such as wind and solar, has increased substantially. Accordingly, the Commission's regulations implementing PURPA are no longer just and reasonable because they do not reflect today's energy markets and result in customers over-paying for QF energy. As discussed herein, the NOPR provides both clarifying guidance and additional tools to the states to address these issues and it appropriately implements the requirements of the statute.

Respectfully Submitted,

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Attachment A

An Empirical Analysis of Avoided Cost Rates for Solar and Wind QFs Under PURPA

Concentric Energy Advisors

AN EMPIRICAL ANALYSIS OF AVOIDED COST RATES FOR SOLAR AND WIND QFS UNDER PURPA

NOVEMBER 2019

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I. Introduction

This analysis compares contract rates for solar and wind generation set pursuant to the Public Utility Regulatory Policies Act[1] ("PURPA") to contract rates set in the competitive market. The analysis is performed by examining a sample of contracts executed between utilities and solar and wind generation facilities that qualify as small power producers – qualifying facilities or "QFs" – under PURPA. Our analysis of a sample of 708 QF contracts representing approximately 8,000 megawatts ("MW") shows that the QF contract rates consistently exceed market-based contract rates for solar and wind energy. Further, we find that these QF contract rates do not reflect the price change observed in competitive markets.

On an annual levelized cost basis, the solar QF contracts signed between 2013 and 2019 exceeded a competitive market rate by between $6.27/MWh and $10.79/MWh in 2018 dollars.[2] We also estimate this cost-per-MWh differential results in an estimated overpayment relative to the market-based alternative of between $67.9 million and $116.8 million per year for the solar QF contracts we reviewed. Accounting for the full term of the solar QF contracts raises the total overpayment estimate to between $1.05 billion and $1.87 billion.

For wind QF contracts signed between 2009 and 2018, we estimate that QF contract rates are between $17.66/MWh and $21.19/MWh higher on an annual levelized basis than comparable market-based contract rates. The differential for the wind QF contracts we reviewed results in estimated overpayments relative to a market-based alternative of between $82.9 million and $99.4 million per year we reviewed. Accounting for the full term of the wind QF contracts raises the total overpayment estimate to between $1.65 billion and $1.99 billion.

Our analysis of levelized cost of energy ("LCOE") trends found that the administratively determined avoided cost rates for the solar QFs established pursuant to PURPA did not reflect underlying declining installation cost trends. For example, Lazard estimates that solar PV and wind LCOEs declined by 89% and 70%, respectively, over the 2009-2019 period.[3] Our results corroborate the findings of state public utilities commissions ("PUCs")[4] that the avoided cost

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[1] 16 U.S.C. 796(17)-(18), 842a-3.

[2] Unless specified otherwise, all figures in this report are presented in 2018 dollars.

[3] Lazard, *Lazard's Levelized Cost of Energy Analysis – Version 13.0*, November 2019, at 8. Note that Lazard's LCOE estimates do not include the impacts of state and federal tax incentives or other subsidies. *See also* U.S. Energy Information Administration, *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*, November 22, 2016, which estimated that solar and wind overnight capital costs for solar and wind declined by 67% and 25%, respectively, between 2013 and 2016.

[4] *See, e.g.*, The Honorable Travis Kavulla, Vice Chairman, Montana Public Service Commission before the United States House of Representatives Committee on Energy & Commerce Subcommittee on Energy hearing entitled "Legislation Addressing LNG Exports and PURPA Modernization", January 19, 2018, Exhibit A.

rates established under PURPA guidelines do not reflect market trends and often exceed market-based metrics.

II. Background: PURPA and Recent Trends in Renewable Generation Costs

Congress passed PURPA in 1978 and required the Federal Energy Regulatory Commission ("FERC") to establish regulations to implement the law. State PUCs are required to adopt rules that comply with FERC regulations when implementing PURPA within their state.[5] PURPA generally requires all electric utilities to purchase electricity at "avoided cost" from QFs, which can take the form of "cogeneration facilities" and "small power production facilities that are 80 MW or smaller." Congress amended PURPA, once, through the Energy Policy Act of 2005 ("EPAct 2005") to allow FERC to terminate the mandatory purchase obligation if FERC finds that specific criteria are met.[6] In implementing EPAct2005, FERC found that QFs of 20 MW or less are not presumed to have access to wholesale markets.[7]

FERC defines avoided cost as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[8] Today, solar and wind facilities are the most common types of small power production facility QFs in the United States.

State PUCs determine the methods utilities must use to calculate the avoided cost energy and capacity rates paid to QFs, but these methods vary significantly.[9] Avoided cost energy and capacity rates are typically developed through one of the following methods: the utility's next planned unit; the estimated cost of a new marginal unit (typically a peaking unit); the estimated systemwide costs from a production cost model; a fuel-indexed rate; a market-based price or index; or a request for proposal ("RFP") process.[10] Generally speaking, smaller QFs less than 100 kW receive avoided cost rates pursuant to a standard tariff as required by FERC, while larger QFs

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[5] FERC's PURPA regulations are contained in 18 C.F.R. §§ 292. Several resources are available to provide a background on PURPA, which is not the focus of this whitepaper. We recommend R. Burns and K. Rose, *PURPA Title II Compliance Manual*, March 2014, for further background.

[6] FERC revised its PURPA regulations in 2006 in Order No. 688, *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Order No. 688, 117 FERC ¶ 61,078 (2006).

[7] 18 C.F.R. §§ 292.601(c)1. FERC proposed to reduce this threshold from 20 MW to 1 MW in a September 2019 Notice of Proposed Rulemaking, *Notice of Proposed Rulemaking, Qualifying Facility Rates and Requirements*, 168 FERC ¶ 61,184 (2019).

[8] Under PURPA, the rates electric utilities pay QFs must be: 1) just and reasonable to the electric utility's customers and in the public interest; non-discriminatory toward QFs and cogenerators; and not exceed the "incremental cost to the electric utility for alternative Energy. See e.g. 16 U.S.C. 841a-3(b) and 3(d).

[9] QFs can seek relief from FERC if they believe that a state Commission has not complied with FERC's PURPA regulations.

[10] R. Burns and K. Rose, *PURPA Title II compliance Manual*, March 2014, at 6.

receive a rate that is negotiated with the utility according to a methodology approved by the state PUC.[11] The cost of QF purchases is ultimately borne by customers.

Robust competitive electricity markets largely did not exist when PURPA was enacted in 1978, so with FERC's guidance, state PUCs used administrative methods as the only available mechanism to estimate a utility's avoided cost.[12] However, as recognized in EPAct2005, competitive electricity markets have developed throughout the U.S. in the past 40 years and now provide a means to estimate a competitive benchmark for a utility's avoided cost for energy and capacity.

Congress also instructed FERC to review PURPA implementation rules "from time to time."[13] In addition to the creation and growth of competitive electricity markets, the fuel mix for electric generation has evolved significantly since PURPA was enacted. For example, 1.9% of electric generation in the U.S. came from solar and wind facilities in 2009, which increased to 9.7% in the first six months of 2019.[14] Furthermore, the U.S. Energy Information Administration forecasts that renewable facilities are projected to be the most common source of generation additions in the U.S. through 2050.[15]

The growth in renewable resources has been driven by state and federal policies to promote renewable energy, consumer demand and declining installation costs. The installation costs of solar and wind generation have declined dramatically in recent years due to technological improvements, resulting in a significant decline in the contract rates of competitively determined purchased power agreements ("competitive PPAs") for solar and wind. For example, the Lawrence Berkeley National Laboratory ("Berkeley Lab") found that the levelized competitive PPA prices for utility-scale photovoltaic solar declined by \$20/MWh to \$30/MWh per year (in 2017 dollars) on average between 2006 and 2012. Competitive solar PPA prices declined by a smaller amount – approximately \$10/MWh per year – between 2013 and 2016.[16] Based on a

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[11] FERC defined 100 kW standard QF contract size in 18 CFR 292.304(c)(2). Note that some states offer standard contracts to qualifying facilities larger than 100 kW. For example, Oregon offers standard contracts to solar facilities up to 3 MW and other small power production facilities up to 10 MW.

[12] See e.g., American Paper Institute v. AEP, 461 U.S. 402, 417 (1983) ("The Commission's order makes clear that the Commission considered the relevant factors and deemed it most important *at this time* to provide the maximum incentive for the development of cogeneration and small power production, in light of the Commission's judgment that the entire country will ultimately benefit from the increased development of these technologies and the resulting decrease in the Nation's dependence on fossil fuels") emphasis added.

[13] 16. U.S.C. 824a-3(a).

[14] US Energy Information Administration, September 2019 Monthly Energy Review, Table 7.2b Electricity Net Generation: Electric Power Sector.

[15] U.S. Energy Information Administration, 2019 Annual Energy Outlook, Reference Case forecast of electric generation capacity. Note that "renewable energy" also includes hydroelectric generation but the majority of renewable growth is expected to come from non-hydro renewables like solar and wind.

[16] M. Bolinger and J. Seel, *Utility-Scale Solar Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States – 2018 Edition*, September 2018, at 35.

sample of competitive wind PPA prices from the Berkeley Lab, the Department of Energy's ("DOE") Office of Energy Efficiency & Renewable Energy estimates that competitively determined PPA prices for wind in the interior U.S. region have declined from an average of $57/MWh in 2009 (in 2018 dollars) to $20/MWh in 2017, a gross decline of 65% and a compound average decline of 12.3% per year.[17]

FERC and state PUCs have observed that the administrative methods state PUCs use to determine avoided cost rates for QF contracts have not always tracked the declines observed in competitive markets.[18] As a result, state PUCs have identified numerous instances of specific utilities overpaying for renewable QF energy and capacity relative to rates available through market mechanisms, with such overpayments ultimately being borne by utility consumers.[19] The analysis presented below estimates the extent to which the QF contract prices in the sample differ from the observed market trends of competitively determined wind and solar PPAs executed in the last seven years for solar QFs and last 10 years for wind QFs.

III. Data and Methodological Approach

This section describes the data and methods used in the analysis. QF contract rates were provided by several utilities on a confidential basis, and as such, the results are aggregated by QF contract execution year to maintain the confidentiality of the utilities and QFs. Competitive PPA benchmarks were derived from a sample of competitive PPA prices collected by the Berkeley Lab, with sensitivities to account for possible differences in contract term. The competitive PPA benchmarks represent contract rates the utilities may have been able to execute for solar and wind generation at market-based prices, as opposed to the administratively determined avoided cost rates paid to QFs. The remainder of this section describes the data and methods used to estimate the competitive benchmarks used to compare with the administratively determined QF contract rates in the sample.

A. QF contract sample background

Table 1 indicates the number of solar and wind QF contracts in the sample and the total capacity as measured by nameplate capacity in MW. The QF contracts were analyzed based on the year they were executed to determine the extent to which the administratively determined avoided cost QF rates followed market and cost trends for solar and wind. The QF contracts in the sample

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[17] U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, 2018 Wind Technologies Market Report at 59. Over 80% of wind capacity in the U.S. is located in the Interior region which generally covers the central U.S (see *Id.* at p 2, Figure 1).

[18] See e.g., *Notice of Proposed Rulemaking, Qualifying Facility Rates and Requirements*, 168 FERC ¶ 61,184 (2019) at note 101.

[19] See e.g., The Honorable Travis Kavulla, Vice Chairman, Montana Public Service Commission before the United States House of Representatives Committee on Energy & Commerce Subcommittee on Energy hearing entitled "Legislation Addressing LNG Exports and PURPA Modernization", January 19, 2018, Exhibit A.

represent most and, in many cases, all solar and wind QF contracts the utilities in the sample have signed since 2009 (the sample does not include QF contract renewals). The unit of observation is a single QF contract with one exception: one utility that provided the total QF contract capacity that was executed at each administratively determined avoided cost rate during the sample period.

Table 1: Summary of QF contract sample

	Solar	**Wind**
Number of QF contracts	629	79
Total capacity	6,311 MW	1,670 MW
Average QF capacity	9.2 MW	21.14 MW
Sample period	2009-2019	2009-2019
States	7	7

Note: All capacity is reported in nameplate MW_{ac}. The average capacity figure excludes records from a utility that provided aggregated QF contract information by contract vintage rather than individual QF facility. The total capacity and number of QF contract figures include this utility.

The QFs in the sample are generally located in states with a significant number of QFs. Additionally, some of the states in the sample are in the footprint of an organized wholesale electricity market (i.e., an independent system operator ("ISO") or regional transmission organization ("RTO")), and some are not. While not a national sample, the data from 708 QF contracts examined provide valuable insights about administratively determined avoided cost rates established under PURPA for both wind and solar generation.

B. Competitive PPA benchmark prices

The analysis uses a sample of third-party utility-scale competitively determined solar and wind PPA data collected and maintained by the Berkeley Lab to estimate a market-based benchmark price for the QF contract rates in the sample. Berkeley Lab provides the caveat that the competitive PPA prices it maintains should be analyzed for trends rather than focusing on specific price points.[20] Thus, while our analysis calculates annual benchmarks and price differentials, we use weighted-average PPAs each year and focus more on the general trends over the sample period. As described below, the Berkeley Lab competitive PPA prices provide a means to

[20] See e.g., M. Bolinger and J. Seel, Berkeley Lab, *Utility-Scale Solar, Empirical Trends in Project Technology, Cost, Performance, and PPA pricing in the United States – 2018 Edition*. U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, *2018 Wind Technologies Market Report*, September 2018, at 59.

determine if the QF contract prices in the sample have generally aligned with trends in U.S. solar and wind markets.

1. Berkeley Lab competitive PPA sample

The competitive solar and wind PPA prices in the Berkeley Lab sample are presented on a levelized basis, as are the QF contracts.[21] Two-thirds of the competitive PPA contracts are nominal fixed-price contracts (i.e., the price in real terms declines at the rate of inflation). For the sake of brevity, we frequently refer to the levelized competitive PPA prices and levelized QF PPA prices as "PPA prices" and "QF prices," respectively. The Berkeley Lab competitive PPA sample is composed of contracts that included the long-term bundled sale of renewable energy credits ("RECs"), energy, and capacity. The sample excludes long-term contracts established under PURPA (e.g., the QF contracts in our sample) and contracts with rates set through a feed-in tariff.[22]

Some wind and solar QF contracts in the sample do not include the value of the facility's renewable attributes (e.g., RECs), and others do. Given this, the prices of the competitive PPAs used in this analysis (which include renewable attributes) are higher than they would have been had the competitive PPAs excluded renewable attributes. In this respect, the competitive PPA prices are a conservative benchmark for a QF contract that does not include the QF's renewable attributes. The competitive PPA prices also reflect federal and state tax incentives and are presented by Berkeley Lab on a regional basis.[23] QFs are also eligible for federal and state tax incentives.

The Berkeley Lab PPA sample of competitive, utility-scale, solar PPA prices consists of 232 contracts totaling 14,461 MW of capacity signed as early as 2006. All of the competitive solar PPAs in the sample are associated with "utility-scale" projects that are 5 MW_{ac} or larger.[24] The competitive solar PPA sample composition prior to 2013 did not align with the geographic location of the utilities in the sample, so this analysis only uses competitive solar PPAs signed in 2013 or later. The competitive PPAs in the Berkeley Lab sample signed before 2013 are largely based on projects in California and the Southwest and thus do not provide a meaningful

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[21] Berkeley Lab estimates levelized costs based on revenues during the life of the contract and assumed a 7% discount rate. The QF contracts were provided in, or converted to, a levelized rate.

[22] State feed-in-tariff programs generally obligate retail utilities to purchase electricity from renewable producers under standard arrangements that specify prices, terms and conditions. As such, feed-in tariff rates are not the product of the market-based arms-length negotiations that produced the competitive PPA prices in the Berkeley Lab sample.

[23] See e.g., M. Bolinger and J. Steel, *Utility-Scale Solar, Empirical Trends in Project Technology, Cost, Performance, and PPA pricing in the United States – 2018 Edition*, September 2018, at 30.

[24] M. Bolinger and J. Steel, *Utility-Scale Solar, Empirical Trends in Project Technology, Cost, Performance, and PPA pricing in the United States – 2018 Edition*, September 2018, at 4.

benchmark for the QFs in the sample. Competitive PPAs signed in California and the Southwest still constitute a significant portion of the data set after 2012, but the sample became more representative of other regions after 2012, which is the first year we use in this analysis.[25,26] The Berkeley Lab competitive solar PPA sample includes PPAs executed in regions that align with the QF contracts in the sample throughout the 2013-2019 period, making these competitive PPAs a reasonable and robust source from which to estimate market-based prices for solar.[27]

The Berkeley Lab sample of competitive wind PPAs included 448 PPAs totaling 42,018 MW of wind projects built as early as 1998.[28] The competitive wind PPA sample consists of utility-scale wind projects, which Berkeley Lab defines as having individual turbines of 100 kW or larger.[29] The regional composition of the competitive wind PPAs is more closely aligned with the states in the QF sample throughout the sample period, so competitive wind PPAs signed on or after 2010 can be used as a reasonable basis to estimate competitive market benchmarks for the wind QFs in the sample.[30]

The Berkeley Lab sample includes competitive PPAs that vary by size, and project design and engineering. However, the evidence suggests that specific technology choice or project size does not have a significant impact on competitive PPA pricing. For example, the Berkeley Lab found that beyond a certain threshold size, which the QFs in the sample exceed, project size is not a key determinant of utility-scale competitive solar PPA prices.[31] Additionally, other DOE research demonstrates that wind installation costs fall when comparing projects in the 5-MW or less range

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[25] See e.g., M. Bolinger and S. Weaver, *Utility-Scale Solar 2015 An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States*, Berkeley Lab, August 2016, at 30.

[26] Furthermore, research indicates that solar installation costs in California exceeded costs in other areas of the nation (including states in the QF sample), which suggests that the competitive PPAs from the early years of the sample may be too high to compare with states other than California. See e.g. Fu, R., D. Feldman, and R. Margolis, *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018*, National Renewable Energy Laboratory, November 2018, Figure 27 "Q1 2018 benchmark by location: 100-MW utility-scale PV systems, EPC only (2018 USD/Wdc)", which shows that California is estimated to have higher installation costs than most states.

[27] M. Bolinger and S. Weaver, *Utility-Scale Solar 2015 An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States*, Berkeley Lab, August 2016, at 36, Figure 20.

[28] U.S. Department of Energy Office of Energy Efficiency & Renewable Energy, *2018 Wind Technologies Market Report*, August 2019, at 58.

[29] U.S. Department of Energy Office of Energy Efficiency & Renewable Energy, *2018 Wind Technologies Market Report*, August 2019, at 1.

[30] U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, *2018 Wind Technologies Market Report*, August 2019, at 60, Figure 54.

[31] M. Bolinger and J. Seel, *Utility-Scale Solar 2015, An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States*, Berkeley Lab, August 2016, at 16.

to the 5- to 20-MW range; economies of scale become less prevalent as projects increase above 20 MW.[32]

The same is generally true for project design and engineering. For example, the Berkeley Lab found that within the sample of competitive solar PPAs, "the executed PPA price is the same regardless of the ultimate project configuration, suggesting that the choice of tracking versus fixed-tilt or [crystalline silicon] versus thin-film is (at least in these cases) not a critical determinant of PPA pricing."[33] Accordingly, we do not adjust the competitive PPAs in the Berkeley Lab sample for size or technology.

Overall, the Berkeley Lab sample of competitive PPAs are not a perfect market-based proxy for the QFs in the sample because, like the solar and wind QF samples, they are based on a diverse set of different wind and solar projects and PPA terms. The competitive benchmarks should not be considered direct substitutes for QF rates, rather these market-based benchmarks should be viewed as indicators of likely competitive contract rates and as such provide a meaningful estimate of the extent to which the sample of solar and wind QF contracts compare to market trends for solar and wind energy over the same period.

2. Contract term sensitivity

The term of the contracts in the Berkeley Lab sample of levelized competitive PPAs has various term lengths, with 20 years being quite common.[34] Contracts in the QF sample range from five (only one) to 25 years, with many having a 15-year term. To compare the two samples, we performed a sensitivity to estimate the impact of a shorter PPA term on the competitive PPA prices. The evidence varies regarding the contract term length required to finance solar and wind facilities. This analysis is agnostic on the issue, and we performed this sensitivity for comparison purposes between the QF and Berkeley Lab samples only.

We estimated the impact of reducing the term of a competitive PPA price from 20 to 15 years under two approaches. The first approach assumes that the project's costs are recovered ratably over the term of the competitive PPA and revenues remain constant in real terms during the life of the project. Under this scenario, a 15-year and 20-year competitive PPA price would be the

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[32] U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, *2018 Wind Technologies Market Report*, August 2019, at 51-52 and Figure 47.

[33] M. Bolinger and J. Seel., *Utility-Scale Solar 2015, An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States*, August 2016, at 33, note 46.

[34] For solar, *see e.g.*, M. Bolinger and J. Steel, *Utility-Scale Solar, Empirical Trends in Project Technology, Cost, Performance, and PPA pricing in the United States – 2018 Edition*, Berkeley Lab, September 2018, at note 39 stating that the average term is 22.5 years and the sample range is 3-34 years. For wind, competitive PPA contract terms range from 5 to 35 years, with 20 being the most common at 56% of the sample. *See* U.S. Department of Energy Office of Energy Efficiency & Renewable Energy, *2018 Wind Technologies Market Report*, August 2019, at note 64.

same regardless of term. If merchant energy revenues were forecast to rise at a rate above inflation during and after the initial PPA term, we would then expect to see a shortening in PPA term to result in a lower competitive PPA rate as project owners seek to realize these higher revenues following the expiration of the initial PPA. This scenario has been referenced in various industry articles as a means of explaining low observed competitive PPA rates.[35] The second approach is to simply assume that the present value of all project costs is collected during a 15-year period and not 20 years. Under this scenario the 15-year competitive PPA rate would be 9.7% higher than the 20-year competitive PPA rate at a weighted average cost of capital of 12%. Accordingly, we present two competitive PPA benchmarks: one that assumes a 15-year competitive PPA price is equivalent to a 20-year competitive PPA price and a sensitivity that increases the Berkeley Lab PPA prices by 9.7% to account for the fact that 15-year competitive PPA prices may be higher than 20-year competitive PPA prices.

C. Levelized Cost of Energy

The levelized cost of energy of a given project is the present value of that project's costs, levelized on an annual basis.[36] Although a given project's LCOE does not generally equal a competitive PPA price for that project, the Berkeley Lab found that for both solar[37] and wind,[38] a project's LCOE closely tracks its competitive PPA price. As such, after accounting for applicable incentives that reduce a project's costs, a project's LCOE can be used as a "first order approximation" of that project's competitive PPA price.[39] We used the relationship between competitive PPAs and LCOEs to estimate the extent to which wind and solar QFs' contract prices aligned with market trends, notably the steep decline in the installed costs of solar and wind observed during the 2009-2019 period.

We used the National Renewable Energy Laboratory's ("NREL") Cost of Renewable Energy Spreadsheet Tool ("CREST") model to estimate how the LCOE of generic solar and wind projects changed over the 2009 to 2018 period in the states included in the sample. The state-level solar and wind LCOE estimates produced accounted for differences in state-level tax rates and solar and wind capacity factors. The LCOEs also included the federal investment and production tax

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[35]See e.g., E. Merchant, *Is the Utility-Scale Solar Industry in a Finance Bubble?*, Greentech Media, January 23, 2019, and C. Roselund, *BENF: Betting on residual value is putting solar projects at risk*, PV Magazine, November 28, 2016.

[36] A generation project's LCOE depends on several assumptions, such as installation costs, capacity costs, taxes, project performance, and assumed project life.

[37] M. Bolinger and J. Steel, Berkeley Labs, *Utility-Scale Solar, Empirical Trends in Project Technology, Cost, Performance, and PPA prices in the United States – 2018 edition*, at 41. Specifically, "Levelized PPA prices track the LCOE of utility-scale PV reasonably well."

[38] U.S. Department of Energy, Office ore Energy Efficiency & Renewable Energy, *2018 Wind Technologies Market Report,* at 69. Specifically, "PPA price trends reflect the levelized cost of wind energy".

[39] U.S. Department of Energy, Office ore Energy Efficiency & Renewable Energy, *2018 Wind Technologies Market Report*, at 69.

credits and assumed that installation costs, which were based on NREL estimates, only varied by year and not across states. We made this simplifying assumption because the focus of our LCOE analysis was to track the trend in solar and wind LCOEs over the sample period rather than differences in LCOEs across states. We assumed a 20-year project life and 60/40 debt/equity ratio with cost of debt and equity of 8% and 12%, respectively for the generic solar and wind projects.[40]

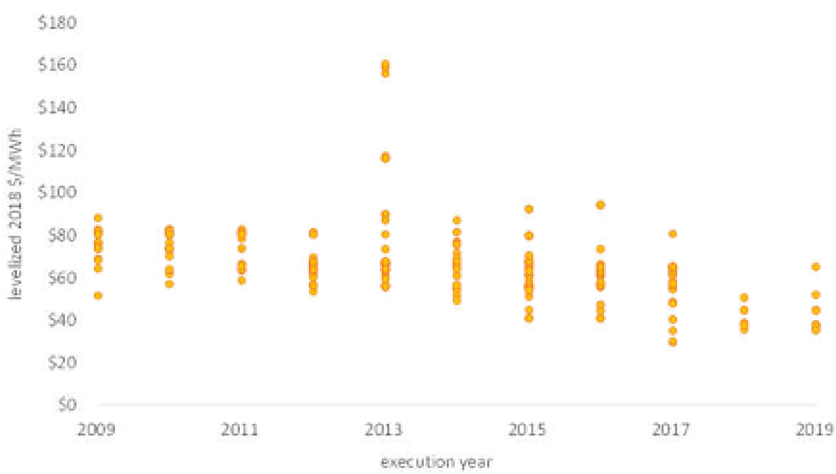
IV. Results

The results of our analysis of the solar and wind QFs are provided below. Unless otherwise indicated, all dollar figures are presented in 2018 constant dollars.[41]

A. Solar

Figure 1 below shows levelized QF contract rates by year of execution for the 629 solar QF contracts in the sample. Pursuant to PURPA regulations, these QF contract rates are based on the purchasing utility's avoided cost. It is not surprising that the avoided cost rates would diverge significantly from the competitive PPA benchmarks we estimate because avoided cost rates are not designed to track the cost to provide solar (or wind) energy. Rather, the avoided cost benchmarks are designed to reflect the utility's administratively determined avoided cost at a specific time based on the methodology used by the state PUC. As noted, the methods states use to determine a utility's avoided cost often do not reflect current market conditions and can vary significantly.

Figure 1: Solar QF sample by contract vintage



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[40] Capital costs and debt to equity ratio are based on those used by Lazard in its *Lazard's Levelized Cost of Energy Analysis – Version 13.0*, November 2019, at 2.

[41] Dollar figures were converted to constant 2018 dollars using the Producer Price Index.

1. Solar QF comparison with competitive PPA benchmarks

Table 2 compares the solar QF avoided cost rates with two benchmark competitive PPA rates we developed from the Berkeley Lab sample described in Section III.A. The first benchmark is the annual MW-weighted average levelized competitive PPA rate of solar PPAs from the Berkeley Lab sample (column 3 in Table 2 - "MW-wtd. avg. competitive PPA benchmark"). Although, in 2013, the competitive benchmark solar PPA rate and the sample average QF rate were roughly comparable, at \$68.49/MWh and \$69.02/MWh, respectively, the QF rates did not decline over time as rapidly as the competitive solar PPA prices.

The fourth column of Table 2 ("MW-wtd. avg. competitive PPA benchmark") compares the MW-weighted average QF contract rates to our competitive PPA benchmark for contracts executed through a market-based process in the same year. Specifically, we subtracted the applicable annual competitive PPA solar benchmark from each QF in the sample, and the fourth column of Table 2 presents the MW-weighted average of this difference by QF contract execution year. Over the 2013-2019 period, this difference ranged between \$0.53/MWh and \$20.08/MWh. The fifth column of Table 2 ("QF rate less PPA rate X total MWh") multiplies the \$/MWh differences from the fourth column by the estimated annual MWh associated with each solar QF contract and aggregates that figure by contract execution year.[42] Analyzing all the QF contract vintages (i.e., QF contracts signed between 2013 and 2019) results in an estimated overpayment of \$116.8 million per year on a levelized basis, or \$10.79/MWh on average.

As described in Section III.B.2, we performed a sensitivity on the competitive PPA benchmark prices to account for the potential contract term difference between the Berkeley Lab solar competitive PPAs and the QF contracts. This adjustment, shown in columns 6 through 8 of Table 2, increased the competitive PPA rates by 9.7% ("PPA15") and reduced the estimated MW-weighted average differential between the QF and competitive PPA rates over the 2013-2019 period from \$10.79/MWh to \$6.27/MWh. After accounting for the MWh associated with each QF contract, the term sensitivity reduced the estimated overpayments from \$116.8 million to \$67.9 million.

[42] Estimates were based on QF nameplate capacity and average solar capacity factors by state from the Berkeley Lab, available at https://emp.lbl.gov/pv-capacity-factors.

Table 2: Solar QF avoided cost rates versus competitive PPA benchmarks (2018 $)

		Competitive benchmark PPA			Term sensitivity (PPA15)		
Year	MW-wtd. avg. QF rate ($/MWh)	MW-wtd. avg. competitive PPA benchmark ($/MWh)	MW-wtd. avg. QF rate less PPA rate ($/MWh)	QF rate less PPA rate X total MWh ($000)	Term-adjusted benchmark PPA15 ($/MWh)	MW-wtd. avg. QF rate less PPA15 rate ($/MWh)	QF rate less PPA15 rate X total MWh ($000)
2013	$69.02	$68.49	$0.53	$1,645	$75.13	($6.11)	-$6,993
2014	$62.29	$55.82	$6.47	$15,432	$61.24	$1.05	$979
2015	$62.37	$47.38	$14.99	$39,939	$51.97	$10.39	$27,170
2016	$59.49	$39.40	$20.08	$19,114	$43.23	$16.26	$15,481
2017	$50.33	$42.69	$7.65	$9,074	$46.83	$3.50	$3,487
2018	$41.74	$22.52	$19.22	$12,941	$24.70	$17.04	$11,474
2019	$39.38	$22.52	$16.86	$18,671	$24.70	$14.68	$16,254
Compound average annual growth rate							
	-8.9%	-16.9%			-16.5%		
Aggregate annual difference across vintage and MWh per year							
				$116.8 million or $10.79/MWh			$67.9 million or $6.27/MWh

Note: All $/MWh figures are presented on levelized annual basis.

The estimates in Table 2 are only presented on an annual basis because it is not entirely clear if and when each QF project came online. However, once a QF comes online, the differences between the QF rate and the competitive PPA benchmarks would persist for the term of the QF contract. Accounting for the term of each solar QF contract results in a total overpayment estimate of $1.87 billion if the competitive PPA benchmark price is used, and $1.05 billion if the term sensitivity benchmark PPA15 is used. However, we caution that some of the contracts in the sample may not go into execution or may terminate prior to their initial contract term, so actual overpayments could be lower.

Beyond exceeding our competitive solar PPA benchmark on an absolute level, the trend in the solar QF contract rates did not follow general market trends for solar energy. For example, the trend in avoided cost rates observed in the QF sample – as measured by the change in the MW-weighted average annual QF contract price – declined at an average annual rate of 8.9% over the 2013 to 2019 period. This rate of decline was much slower than the competitive solar PPA prices – also measured as the change MW-weighted annual average – which declined at a rate of 16.9% over the same period. Figure 2 presents calculations in Table 2 graphically.

Figure 2: Solar QFs and competitive PPA benchmarks

It is important to note that the analysis in Table 2 compares the solar QF contract rates to competitive PPAs for solar energy. This analysis does *not* compare the QF contract rates to the purchasing utility's actual avoided cost, which is likely to be much lower (e.g., energy purchased from an ISO/RTO or a liquid trading hub). As such, the overpayments we estimate in Table 2 are likely to be lower than any utility estimates of the extent to which that utility's QF contracts exceed its actual avoided costs. The same is true for the wind QF contract analysis in Table 3 below.

2. Solar levelized cost of energy trends

Given the relationship between a solar project's LCOE and the competitive solar PPA rate noted in Section III.C above, we also estimated how the avoided cost rates in QF contracts compared to the LCOE of a generic solar project. The LCOE estimates we calculated are a rough approximation of each QF project's LCOE because we do not have sufficient information to estimate each QF's LCOE.

However, it is informative to compare the trend of the sample QF contract rates with the LCOE of a generic unit of the same type. We used NREL's CREST model and solar installation benchmark cost data between 2010 and 2018 to calculate the LCOE of a generic fixed-tilt utility-scale solar system in each state that a solar QF in the sample was located. Figure 3 plots the MW-weighted average of these state-level solar LCOEs for purposes of comparison with the MW-weighted average solar QF contract price each year. For this comparison, we assume that the 2009 MW-weighted average QF contract rate changes throughout the sample at the same year-over-year change as the generic photovoltaic LCOEs estimated in CREST (green line in Figure 3).[43] Our solar

[43] We calculated the generic solar PV project trend by computing MW-weighted average of the generic project's LCOE each year, using the MW of QFs executed in each state that year as weights.

LCOE estimates indicate that the solar LCOE in the states in the sample declined by 73.1% over the 2009-2018 period, which was significantly higher than the 45.5% decline observed in the MW-weighted average QF solar contract rate over the same period. Our LCOE estimates are roughly in line with Lazard's November 2019 LCOE estimates for solar PV, which Lazard estimates declined by 89% over the 2009-2019 period, or 20% per year on average (gray line in Figure 3).[44]

Figure 3: MW-wtd. avg. solar QF and generic solar PV LCOE trend comparisons

Additionally, NREL found that, from 2010 to 2018, the LCOE of utility-scale PV declined by between 80% and 82%.[45] As shown in Figure 3, the trends in the sample solar QF contracts have not followed well-documented trends in the decline of solar PV installation costs.

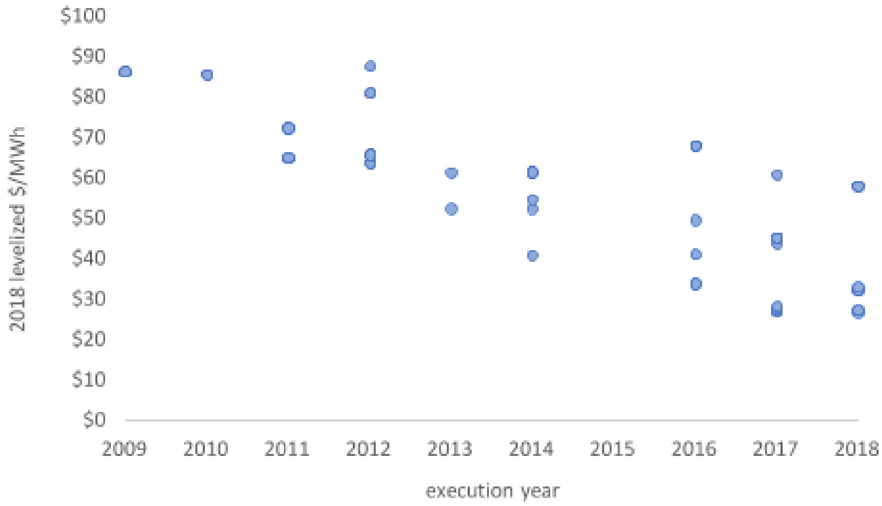
B. Wind

Figure 4 below plots the 79 wind QF contracts in the sample, which, pursuant to PURPA regulations, are based on the purchasing utility's administratively determined avoided cost. The average QF wind avoided cost contract rates, presented here in levelized 2018 $/MWh, declined over the sample period (2009-2018) at a compound average annual rate of 12.4% per year.

[44] Lazard, *Lazard's Levelized Cost of Energy Analysis – Version 13.0*, November 2019, at 8.

[45] R. Fu, D. Feldman, and R. Margolis, *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018*, National Renewable Energy Laboratory, November 2018, at 37.

Figure 4: Wind QF sample by contract vintage



Like the solar analysis described above, we estimated competitive benchmark wind PPAs from the Berkeley Lab wind PPA sample and compared them with the wind QF rates in the sample to determine the extent to which the avoided cost rates reflected the market trends observed during the sample period.

1. Wind QF comparison with PPA benchmarks

Table 3 compares the annual competitive benchmark PPA price and the PPA term length sensitivity PPA15 for the 79 wind QF contracts in the sample. The figures in Table 3 were developed using the same methodology employed to analyze the solar QFs in Table 2. As shown in the fourth column of Table 3, wind QF contract rates exceeded the competitive wind benchmark PPA by between $10.18/MWh and $40.45/MWh over the 2009-2018 period. The average difference for all wind QF contracts executed between 2009 and 2018 yields a weighted-average difference of $21.19/MWh, or $99.4 million per year on a levelized annual basis. Under the term length sensitivity, which adjusts the competitive wind PPA benchmark upward by 9.7% (PPA15), the total dollar difference across the contract vintages falls to $82.9 million per year on a levelized basis, or $17.66/MWh.

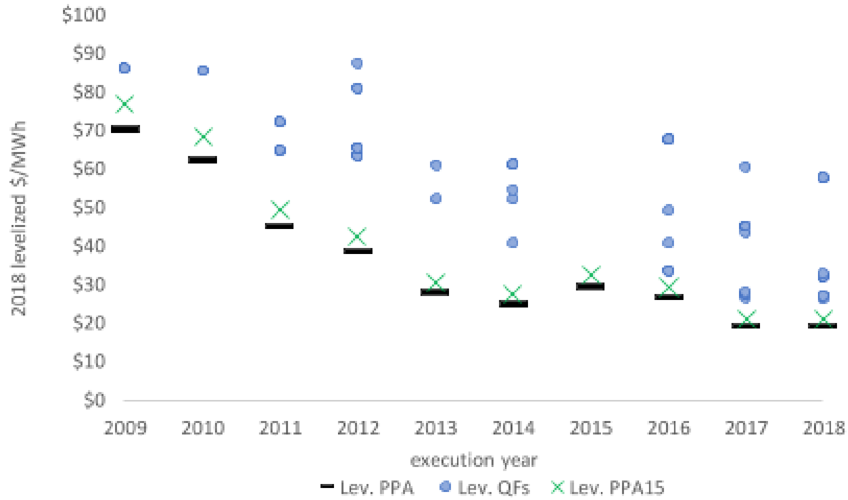
Table 3: Wind QF avoided cost rates versus competitive PPA benchmarks (2018 $)

		competitive benchmark PPA			Term sensitivity (PPA15)		
Year	MW-wtd. avg. QF rate	MW-wtd. avg. competitive PPA benchmark	MW-Wtd. Avg. QF rate less PPA rate	QF rate less PPA rate X total MWh	Term-adjusted benchmark PPA15	MW-Wtd. Avg. QF rate less PPA15 rate	QF rate less PPA15 rate X total MWh
	($/MWh)	($/MWh)	($/MWh)	($000)	($/MWh)	($/MWh)	($000)
2009	$95.63	$70.00	$25.63	20,124	$76.79	$18.84	14,824
2010	$86.24	$62.34	$23.91	11,369	$68.38	$17.86	8,494
2011	$64.22	$45.07	$19.15	4,036	$49.44	$14.78	3,123
2012	$78.93	$38.49	$40.45	16,718	$42.22	$36.71	15,172
2013	$62.88	$27.96	$34.92	8,635	$30.67	$32.21	7,958
2014	$47.97	$25.00	$22.97	9,052	$27.43	$20.54	8,067
2015		$29.44			$32.30		
2016	$49.23	$26.48	$22.75	8,794	$29.05	$20.18	7,758
2017	$31.55	$19.00	$12.55	15,875	$20.84	$10.71	13,526
2018	$29.18	$19.00	$10.18	4,829	$20.84	$8.33	3,946
			Compound average annual growth rate				
	-12.4%	-13.5%					
			Aggregate difference across contract vintages				
			$99.4 million or $21.19/MWh			$82.9 million or $17.66/MWh	

Note: All $/MWh figures are presented on levelized annual basis.

Accounting for the term of the wind QF contracts yields an overpayment estimate of $1.99 billion when using the competitive PPA benchmark price, and $1.65 billion if the adjusted competitive PPA15 benchmark is used. The QF contract rates and competitive PPA benchmarks shown in Table 3 are plotted in Figure 5 below.

Figure 5: Wind QFs and competitive PPA benchmarks



The samples of QF contracts follow the same trend as the competitive PPAs but are generally above the competitive PPAs. Accordingly, as shown in Figure 5, although the trend of QF contract rates in the sample roughly aligns with the trend in the competitive PPA prices over the 2009-2018 period, the QF rates in the sample are approximately $10/MWh to $20/MWh above the observed competitive wind PPA rates, indicating that the administratively determined avoided cost rates do not reflect market-based outcomes.

2. Wind levelized cost of energy trends

As described in Section III.C above, we used the CREST model and wind installation and fixed operations and maintenance cost figures from NREL to estimate the LCOE of a generic wind unit to capture wind installation cost trends between 2009 and 2018.[46] We also assumed a levelized production tax credit of $15/MWh.[47] Figure 6 plots the sample MW-weighted annual average wind QF contract rate against an LCOE trend that was developed by applying the year-over-year percentage change in the MW-weighted annual average wind LCOE estimate to the 2009 MW-weighted average QF contract price. Our wind LCOE estimates indicate that the wind LCOE in the states in the sample declined by 47.8% over the 2009-2018 period, which is lower than the MW-weighted average wind QF contract decline of 69.5%. However, the decline in the wind QF contract rates is roughly in line with Lazard, which estimates that the wind LCOE declined by 70% over the 2009-2019 period, or 11% per year on average (gray line in Figure 6).[48]

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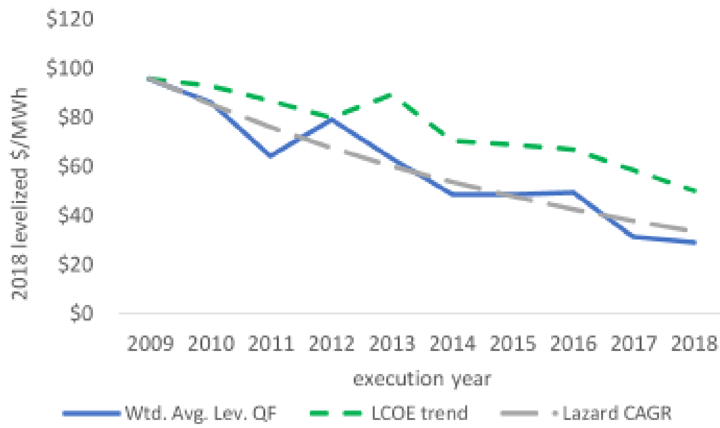
[46] U.S. Department of Energy, Office ore Energy Efficiency & Renewable Energy, *2018 Wind Technologies Market Report,* August 2019, Figure 46 "Installed wind power project costs over time". Like the DOE, we assumed total operational expenses fell from a levelized cost of $52/kW-year in 2010 and fell to $43/kW-year in 2018. *Id*. at 69.

[47] U.S. Department of Energy, Office ore Energy Efficiency & Renewable Energy, *2018 Wind Technologies Market Report*, August 2019, at note 66.

[48] Lazard, *Lazard's Levelized Cost of Energy Analysis – Version 13.0*, November 2019, at 8.

Figure 6: MW-wtd. avg. wind QF and LCOE trend comparisons



Our wind LCOE analysis finds that the sample of wind QFs generally tracked with the LCOE trends we estimated for wind in the states where the QF contracts were located. However, Figure 6 estimates trends and not levels. The analysis in Table 3 and Figure 5 demonstrates that the sample wind QF contract rates exceeded the competitive wind PPA rates throughout the sample period.

V. Using markets to calculate avoided costs

The market for competitive solar and wind generation is highly robust and competitive, which means that market prices are readily available to establish avoided cost rates for QF energy and capacity contracts. Such market-based avoided cost rates are preferable to administratively determined rates because, as shown above, administratively determined rates can become divorced from market conditions and result in customer overpayment.

Setting QF contract rates administratively without regard to current market conditions can also result in inefficient investment over time because such rates encourage developers to locate in jurisdictions with the highest avoided cost rates as opposed to areas where solar and wind energy would be most effectively deployed, and therefore valuable to the utility and its customers. Administratively determined avoided cost rates for QFs that are uniform across a utility's footprint also fail to account for the locational value of energy. Market-based prices based on locational marginal price ("LMP") or a liquid hub adjusted for delivery send better price signals to QF investors about where and when to build. Conversely, failing to provide the proper price signal with avoided cost energy (or capacity) rates gives QF developers the incentive to invest where it is cheapest to build an interconnect, with no guarantee that such locations are those that need additional generation the most.

As noted in a whitepaper by the National Association of Utility Regulatory Commissioners ("NARUC"), a utility-run RFP provides a transparent means to determine a utility's market-based

avoided cost for energy and capacity as compared to administratively determined avoided cost rates.[49] For example, the Public Service Company of Colorado ran an all-source RFP in 2017 as part of its electric resource planning process and received a significant number of bids from renewable developers. Table 4 summarizes the competitive bids that developers submitted in this RFP.

Table 4: Public Service Company of Colorado 2016 All Source solicitation responses

Technology type	# of bids	Bid MW	# of projects	Project MW	Median bid price ($/MWh)
Solar	152	29,710	75	13,435	$29.50
Solar with battery storage	87	16,725	59	10,813	$36.00
Wind	96	42,278	42	17,380	$18.10
Wind and solar	5	2,612	4	2,612	$19.90
Wind with battery storage	11	5,700	8	5,097	$21.00
Wind, solar and battery storage	7	4,048	7	4,048	$36.60

Source: Public Service Company of Colorado, 2016 Electric Resource Plan, 2017 All Source Solicitation 30-day report (Public Version), December 28, 2017, Attachment A.

The median RFP solar bid of $29.50/MWh is almost half of the MW-weighted average solar QF contract price of $59.49/MWh in 2016, without adjusting for inflation. Similarly, the MW-weighted average wind QF contract price in 2016 was $49.23/MWh, over twice the median RFP bid of $18.10/MWh.

[49] T. Kavulla and J. Murphy, *Aligning PURPA with the Modern Energy Landscape A Proposal to FERC*, National Association of Utility Regulatory Commissioners, October 2018.

VI. Conclusions

We found that the avoided cost rates in the sample of solar and wind QF contracts we reviewed generally exceeded rates that are realized in competitive markets for solar and wind energy. We also found that trends in solar QF contracts did not reflect underlying cost trends because solar installation costs declined far faster than the administratively determined QF rates. We estimate that utilities and, in the end, customers overpaid in the approximate range of $150.7 million and $216.2 million per year under the QF solar and wind contracts. Accounting for the full term of the solar and wind QF contracts raises the total overpayment estimate to between $2.7 billion and $3.9 billion, respectively.